

**DOCKET**

**09-IEP-10**

DATE SEP 24 2009

RECD. OCT 14 2009

BEFORE THE  
CALIFORNIA ENERGY COMMISSION

In the Matter of: )  
 ) Docket No. 09-IEP-10  
Preparation of the 2009 )  
Integrated Energy Policy Report )  
(2009 IEPR) )

COMMITTEE WORKSHOP ON THE POTENTIAL NEED  
FOR EMISSION REDUCTION CREDITS IN THE  
SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

CALIFORNIA ENERGY COMMISSION  
FIRST FLOOR, HEARING ROOM A  
1516 NINTH STREET  
SACRAMENTO, CALIFORNIA

MONDAY, SEPTEMBER 24, 2009

10:00 A.M.

Reported by:  
Peter Petty  
Contract Number:



**ORIGINAL**

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member, IEPR Committee

James D. Boyd, Vice Chair and Associate Member,  
IEPR Committee; Presiding Member Transportation and  
Fuels Committee

Kelly Birkinshaw, His Advisor

STAFF PRESENT

Suzanne Korosec, IEPR Lead  
David Vidaver  
Michael Jaske  
Matthew Layton

**Also Present**

Presenters

Mark Minick, Southern California Edison (SCE)  
Catalin Micsa, California ISO (CAISO)  
Kenneth Silver, (LADWP)  
Bruce Moore, LADWP  
Mohsen Nazemi, South Coast Air Quality  
Management District (SCAQMD)  
Barbara Baird, SCAQMD  
Oscar Abarca, SCACMD  
Richard McCann, Aspen Environmental Group  
Cory Welch, Summit Blue  
Larry Kostrzewa, Edison Mission Energy  
Michael Carroll, Latham and Watkins  
Steve Sciortino, City of Anaheim

Panelists (Not Already Listed)

Keith Johnson, CAISO

Public Comment (Via WebEx)

Bruce Rising (PHON)  
Mark Turner, Competitive Power Ventures  
Shana Lazarow, Communities for a Better Environment  
Don Vawter, AES Southland  
Samantha Unger, Evolution Markets  
Adrian Martinez, Natural Resources Defense Council (NRDC)  
Jesse Marquez, Coalition for a Safe Environment  
Gary Rubenstein, Sierra Research  
Jeff Valmus, EmeraChem Power

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

2 SEPTEMBER 24, 2009 10:05 a.m.

3 MS. KOROSSEC: We are going to go ahead and get  
4 started now. Good morning, everyone. I am Suzanne Korosec.  
5 I lead the unit that produces the Energy Commission's  
6 Integrated Energy Policy Report, or IEPR. Welcome to  
7 today's IEPR Committee Workshop on the Potential Need for  
8 Emission Reduction Credits in the South Coast Air Quality  
9 Management District, given state policy goals to reduce the  
10 use of once-through cooling power plants and to retire or  
11 re-power the state's fleet of aging power plants.

12 Just a few housekeeping items before we get  
13 started. Restrooms are in the atrium, out the double doors  
14 and to your left, we have a snack room on the second floor  
15 at the top of the stairs, under the white awning, and if we  
16 have an emergency and we need to evacuate the building,  
17 please follow the staff out the door to the park that is  
18 diagonal to the building and wait for the all clear signal.

1 Today's workshop is being broadcast through our  
2 WebEx conferencing system. Parties need to be aware that we  
3 are recording the workshop. We will make that recording  
4 available on our website within a couple of days of the  
5 workshop, and we will also be providing a written transcript  
6 approximately two weeks after the date of the workshop.

7 For those of you who are listening in on WebEx, if  
8 you have questions during the day, please send them to the  
9 WebEx Coordinator and we will make pass those on to  
10 presenters. And during the public comment period at the end  
11 of the day today, we will hear first from people who are  
12 here in the room, and then we will open up the lines for the  
13 WebEx participants. For those of you in the room who want  
14 to make comments, we do ask you to come up to the center  
15 microphone at the podium so we can make sure that we capture  
16 your comments in the transcript. And it is also very  
17 helpful if you could give our Court Reporter your business  
18 card so we make sure we get your name and affiliation  
19 spelled correctly.

20 Moving on to our subject for today, the Scoping  
21 Order for the 2009 IEPR identified the need to evaluate the  
22 impacts of potential air pollution limits on new power  
23 generation in the South Coast Air Quality Management  
24 District, and the effect of those limits on efforts to  
25 replace aging power plants. I do need to emphasize that,

1 while we are conducting this workshop as part of the 2009  
2 IEPR, because of the complexity of this issue and all of the  
3 various efforts that are underway that will affect the  
4 outcome, this is simply one point on a longer timeline and a  
5 much longer process. For the 2009 IEPR, we will include the  
6 latest information that we have at the time the IEPR is  
7 published, but parties should not expect that this IEPR is  
8 going to recommend specific solutions to this issue.

9           In February of this year, the Energy Commission  
10 staff released a staff draft paper entitled "Potential  
11 Impacts of the South Coast Air Quality Management District  
12 Air Credit Limitations and Once-Through Cooling Mitigation  
13 on Southern California's Electricity System." I have  
14 included the link to that here for parties who would like to  
15 review that paper. Today's comments and discussions, along  
16 with the written comments will be used to update that staff  
17 paper, and the resulting updated staff report will be  
18 circulated for public comment probably in December with a  
19 final report out in January 2010.

20           Just to note, we are accepting written comments on  
21 today's workshop until 5:00 p.m. on October 6<sup>th</sup>. Copies of  
22 today's agenda are on the table out in the foyer, but, just  
23 briefly, we will start with presentations this morning from  
24 the Energy Commission staff, followed by Southern California  
25 Edison, the California Independent System Operator, the Los

1 Angeles Department of Water and Power on potential  
2 dispatchable capacity needs in Southern California and in  
3 Los Angeles Basin. After that, we will be breaking for  
4 lunch, we will resume in the afternoon with a presentation  
5 on a consultant assessment of Los Angeles Basin Reliability,  
6 and then we will hear from South Coast Air Quality  
7 Management District on PM-10 Market Conditions and Offset  
8 Availability in the South Coast District. Next, we will  
9 have presentations from Edison Mission Energy, Latham and  
10 Watkins, and the City of Anaheim to provide the developer  
11 perspective; and finally, we will have a panel discussion on  
12 Emission Reduction Credit Procurement and Requirements,  
13 followed by an opportunity for public comments. Then, we  
14 will finish up the day with concluding remarks from the  
15 staff. So with that, Commissioner Byron, I will turn it  
16 over to you for opening remarks.

17 COMMISSIONER BYRON: Thank you. Welcome,  
18 everyone. I am Jeff Byron and I chair the Integrated Energy  
19 Policy Report Committee along with the Electricity and  
20 Natural Gas Committee here at the Commission. And with me  
21 is the Vice Chair, Commissioner Boyd, who is the Associate  
22 Member with me on both of those committees. So you might  
23 say we have two of the right five Commissioners here in the  
24 room. Also, to his left is his Advisor, Kelly Birkinshaw.  
25 This is a big topic. Commissioner, do you have anything you



1 want to say before we start?

2           VICE CHAIR BOYD: Very little. But I did not  
3 realize until you said it that we are a dynasty. Anyway,  
4 welcome everybody to this workshop. Appreciate all of you  
5 being here and I am glad to see a reasonably sizeable  
6 audience on this subject because it is more than a sizeable  
7 subject matter. To me, it is not a stand alone issue, it is  
8 an issue that is -- if there is such a word -- co-joined,  
9 linked to, or whatever, a whole lot of other issues that we  
10 are wrestling with at the present time, be it the once-  
11 through cooling, our old policy retiring old and inefficient  
12 plants, or the consequences and ramifications of the  
13 California Climate Change Program and activities. So, as we  
14 come together in an Integrated Energy Policy Report, we have  
15 got to look at it in that context, but today is to really  
16 talk about this specific problem. And there could be hosts  
17 of solutions to these multiple problems, not just repower,  
18 replace, but there is transmission and/or distribution  
19 system and/or more DG, CCHP/ activities or Job 1 in  
20 California is, you know, squeeze all the efficiency we can  
21 out of things, even your television sets, but that is a  
22 different subject for a different day, and welcome any and  
23 all support you want to bring to that subject when we do get  
24 to it. In any event, I look forward, therefore, to the  
25 comments of any and all folks out there who are going to

1 deal with this subject because this is part of an incredibly  
2 rapidly changing dynamic here in California, so we can keep  
3 up with it. Enough said.

4           COMMISSIONER BYRON: Well, I will add my brief  
5 remarks, as well. Thank you for being here. This is a big  
6 issue. It has got all the makings of a blockbuster movie, I  
7 guess. It has got lawsuits, it has got -- I read an account  
8 last night of how the Legislature moved through the Assembly  
9 and the Senate last -- what -- two weeks ago on the 11<sup>th</sup> and  
10 the early morning of the 12<sup>th</sup>, and that was not a pretty  
11 picture. Of course, this issue is bigger than just power  
12 plants, it is unresolved -- maybe one day we are all going  
13 to see books written about it. But in the mean time, we  
14 need solutions. We need solutions that address the health,  
15 environmental concerns, the economic impact, and an interest  
16 of this Commission -- and we believe on behalf of the rest  
17 of California -- is the retirement of aging, less efficient,  
18 and polluting power plants, of which there are up to 8,000  
19 Megawatts that may be retired over the next 10 years.

20           Also, in June of this year, as Commissioner Boyd  
21 indicated, there was another issue that is closely tied to  
22 this, the State Water Resource Control Board issued a draft  
23 policy on the use of ocean water for power plant cooling.  
24 And that means generation units on the coast that are using  
25 OTC will have to either re-fit their cooling, repower, or

1 retire. And that means a great deal of money and  
2 investments will have to be made, but we will also need to  
3 make a lot of investments in energy efficiency, and demand  
4 response, and renewables, and transmission upgrades, and  
5 that will be helpful because, within the LA Basin, that will  
6 help, but not completely mitigate this problem. Many of the  
7 OTC plants will likely retire, but many will still be  
8 needed. Retrofitting may be infeasible, or uneconomic, and  
9 it is going to require either repowering those units, or  
10 retirement or replacement. Retirement or replacement is  
11 going to require Air Emission Credits and ARC's, the Air  
12 Reduction Credits for primarily PM-10, are not available due  
13 to market constraints and litigation.

14           So today, we want to hear from a diverse and  
15 knowledgeable group of folks, we want to understand these  
16 issues, and we want to discuss potential solutions. I am  
17 looking forward to a very constructive and open dialogue  
18 from all of you, this is not a court of law, everyone's  
19 interest is joined here in one way or another, and we are  
20 missing some key folks. Unfortunately, we got a late  
21 request from some of the plaintiffs in the litigation to  
22 move the date for this workshop because they were unable to  
23 attend. I apologize, we were not able to move it. We have  
24 some obligations to get our Integrated Energy Policy Report  
25 done. We will be making recommendations following your

1 input, what we hear today, and your written comments. And I  
2 really hope that we will receive good constructive input  
3 from those parties that were not able to be here today.

4 With that, I would like to thank you all very  
5 much. I am very keen to hear what you all have to say. I  
6 am going to go ahead and turn it over to staff at this  
7 point, and ask them if we can do our best to get through a  
8 lot of information on probably an optimistic schedule, but  
9 we will stay until we get it. Mr. Vidaver.

10 MR. VIDAVER: Thank you, Commissioner. Good  
11 morning. It has been a while since I have used one of  
12 these, there we go. First of all, I want to apologize to  
13 Commissioner Byron, he has declared this hearing room an  
14 acronym-free zone, and the title of my presentation is four  
15 acronyms in the first 10 words, so just to save space. We  
16 have a full day, so I will not dwell on the seriousness of  
17 the issue under discussion.

18 The IEPR record is replete with statements  
19 regarding the need to replace some share of these existing  
20 capacity in the area under District SCAQMD jurisdiction, so  
21 as to both comply with the Water Board policy and once-  
22 through cooling, maintain reliable electric service in  
23 Southern California, and the L.A. Basin, and facilitate the  
24 insertion of intermittent renewables on the scale needed to  
25 meet the State's ambitious renewable energy targets. I

1 think most parties in this room would agree that legislative  
2 solutions that solve this problem one facility at a time are  
3 perhaps not as desirable as a more structured approach that  
4 would address the long-term needs for capacity in the Basin.

5 We have effectively divided the workshop, as  
6 Suzanne intimated, into two halves, the first dealing with  
7 the need for new dispatchable gas-fired capacity in the LA  
8 Basin over the next decade and the planning studies needed  
9 to isolate that range of values; the second half will deal  
10 with associated Emission Reduction Credits and offsets  
11 needed by that capacity and where they might come from.

12 COMMISSIONER BYRON: Mr. Vidaver, if you do not  
13 mind, I apologize, Ms. Korosec just informed me that I am  
14 uninformed, despite the request that we received to delay  
15 the workshop, I understand that a number of the parties  
16 communicated they could not be present today are indeed  
17 here, and I am glad to hear that, we welcome your input.  
18 Please go right ahead.

19 MR. VIDAVER: The inability to permit new power  
20 plants in the area under District jurisdiction is largely a  
21 problem of being unable to do so within two transmission  
22 constrained areas, the California ISO defined Los Angeles  
23 Basin Local Reliability Area and the Los Angeles Basin  
24 portion of the Los Angeles Department of Water and Power  
25 Control Area. Meeting NERC guidelines for maintaining

1 reliable service under extreme peak load conditions requires  
2 threshold amounts of capacity within these areas. The need  
3 for Emission Reduction Credits and offsets is likely to be  
4 greatest within the two areas as the generation units  
5 totaling more than 7,500 Megawatts at seven facilities that  
6 utilize once-through cooling in the area under SCAQMD  
7 jurisdiction all lie in these areas.

8           Now, conceptually, the problems facing planners is  
9 not a difficult one to characterize -- how much capacity do  
10 you need, and where, to meet LA Basin and sub-area capacity  
11 requirements? What does that capacity have to be able to  
12 do, dispatch-wise? And how much will existing capacity be  
13 able to contribute to those requirements? Once you have  
14 answered these questions, you have what you need in Los  
15 Angeles and need only to build enough capacity elsewhere in  
16 Southern California to meet area-wide requirements and share  
17 in that it provides the inertia needed by the system and the  
18 ramping capability needed to incorporate intermittent  
19 renewables.

20           There are a few uncertainties that make that  
21 difficult. Until a full set of compliance plans are  
22 submitted to the Water Board, approved and in place, it is  
23 not certain how much capacity of existing locations will be  
24 able to continue to operate. While it is anticipated that  
25 most once-through cooled units will require replacement, and

1 thus emission reduction credits, it is possible that some  
2 units at existing locations will be allowed to continue to  
3 operate without modification, depending on Water Board  
4 treatment of compliance plans.

5           Transmission upgrades are expected to allow more  
6 energy to be imported into the Los Angeles Basin, reducing  
7 local capacity requirements, and the need for replacement  
8 and new capacity within the Basin. Renewable additions will  
9 affect the need for capacity both within and outside the LA  
10 Basin. Different portfolios of renewable resources will  
11 provide different amounts of capacity on inertia, and result  
12 in different amounts of ramping capability being required in  
13 the rest of the system.

14           Finally, targets for energy efficiency,  
15 approximate set of demand response, and interruptible load  
16 programs, however well estimated, may ultimately prove to be  
17 unreachable within the time periods desired. And even if  
18 one can forecast accurately the need for capacity in the LA  
19 Basin, the Emission Reduction Credits and offsets needed by  
20 this capacity, and the sources from which they might come  
21 are uncertain. This you have all seen.

22           The need for Emission Reduction Credits in the  
23 District over the next decade will be driven to a great  
24 extent by the state of Water Board policy on once-through  
25 cooling. As I mentioned, the draft policy will likely

1 require the replacement of existing turbines and, thus,  
2 Emission Reduction Credits or offsets if they are to  
3 continue to operate. Key questions are, thus, how much of  
4 this capacity will need to be replaced with gas-fired  
5 capacity, located on-site or elsewhere in the LA Basin, and  
6 how much, if any, will be allowed to continue to operate  
7 under, for example, wholly disproportionate clauses in the  
8 final loaded word policy.

9           And, we have to solve all of these problems rather  
10 quickly. Compliance plans due, I believe, six months after  
11 the approval of the policy must include a discussion of how  
12 the facility plans to comply and provide some indication as  
13 to when, by showing that the refitting or repowering is  
14 being coordinated with the ISO, or LADWP, it has generally  
15 exceeded the compliance, or will require repowering or  
16 replacement in most cases. Some modifications, both  
17 physical plant and operation, are necessary within one year  
18 of the approval of the Water Board policy. Unless operators  
19 can demonstrate that reduced flows are necessary for  
20 operations or maintenance, those will have to be reduced.

21           It is anticipated that the cost of plant  
22 modifications must be picked up by counterparty Star  
23 (PHONETIC) contracts. Five years after approval of the  
24 policy, mitigation will be required of those plants that  
25 have yet to comply. Owners can demonstrate that they are



1 doing so for existing efforts, can fund an ongoing  
2 mitigation project, or develop or implement a new project.  
3 In any case, as we expect parties to undertake major  
4 investments, only with a guarantee of cost recovery in the  
5 form of a long-term contract, the dates that these contracts  
6 are offered to facilities are very important. If the Public  
7 Utilities Commission is to authorize the procurement of new  
8 and replacement capacity needed in the LA Basin in the form  
9 of approval of Southern California Edison's 2012 Procurement  
10 Plan at the end of 2012, the ISO's 2012 Transmission  
11 planning process will have to evaluate transmission  
12 alternatives that might affect the need for capacity in the  
13 LA Basin. Failure to adequately consider in-basin needs for  
14 new capacity, as part of the 2012 CPUC Procurement Cycle,  
15 runs the risk of later procurement that restricts the  
16 options available to meet local reliability needs, ignores  
17 transmission solutions, requires gas-fired capacity that  
18 might otherwise not be necessary, and precludes competitive  
19 solicitations, thus raising ratepayer costs.

20 Here are all the power plants involved. We have  
21 seven gas-fired facilities under SCAQMD jurisdiction that  
22 utilize FTC; we have four projects that are going forward in  
23 South's estimation, Inland Empire 2 should be online before  
24 next summer, Cambian (phonetic) should be permitted and  
25 available to the City of Anaheim, the Riverside Expansion 96

1 Megawatts should begin construction shortly, and staff  
2 anticipates that the expansion of the Watson Co-Generation  
3 facility will take place within the next two years. This is  
4 a total of 786 Megawatts. We also have three projects  
5 contracted for by Edison, Walnut Creek, Sentinal and El  
6 Segundo, and three other projects within the Basin who are  
7 currently stalled by the moratorium, the Southeast Regional  
8 Energy Project, also known as the Vernon Project, Sun  
9 Valley, and Hydro. There are also two out-of-area projects  
10 that rely on credits that are currently unavailable,  
11 Palmdale and Victorville 2. It is interesting that, with  
12 the exception of projects coming before the Commission  
13 within the San Diego Los Angeles Reliability Area, and  
14 Blythe 1 and 2, all the gas-fired projects coming before the  
15 Commission are either in SCAQMD jurisdiction, or are relying  
16 on credits -- Palmdale and Victorville 2. This is quite  
17 natural developers would assume that, in anticipation of  
18 needing to replace once-through cooled plants, being able to  
19 provide local reliability services, that most of the  
20 projects we see would be under SCAQMD jurisdiction and  
21 within the local reliability area. So we have a lot of eggs  
22 in one basket.

23           Here are the projects that I alluded to and their  
24 sizes, three still have contracts, four without, and two  
25 outside the Basin, but relying on credits that are stalled

1 by the moratorium.

2           This is pretty ISO-centric. The Water Board  
3 policy affects the Los Angeles Department of Water and  
4 Power. They have planned replacements for two units at  
5 Haynes, and two units at Scattergood, which predate the  
6 Water Board policy. These repowerings or replacements are  
7 designed to integrate additional renewables into their  
8 system, maintain local reliability, and reduce gas-fired  
9 Megawatt hour and Btu per Megawatt hour in the process.  
10 There remains uncertainty, however, regarding both the need  
11 to modify remaining units under their ownership in order to  
12 comply with the Water Board policy, as well as where any  
13 necessary emission reduction credits might come from.

14           Okay, numbers. We have necessary capacity in two  
15 dimensions, both within the Los Angeles Basin and across  
16 Southern California as a whole. I want to deal with the  
17 latter first. You need sufficient capacity in both the LA  
18 Basin and across the entire area in South of Path 26. You  
19 will see that staff estimates of current and near term  
20 reserve margins in Southern California are on the order of  
21 27-28 percent, or more than 3,000 Megawatts above the 15  
22 percent generally exceeded as minimally necessary for  
23 reliability on its own basis. How did we get to this point?  
24 In approving 1,200 to 1,700 Megawatts of new capacity for  
25 Southern California in late 2007, the Public Utilities

1 Commission in the 2006 Procurement Cycle, estimated that SB  
2 26 would be along roughly 1,100 Megawatts in 2010. Since  
3 then, the peak load forecast, here the revised 2009 IEPR  
4 load forecast is used, has dropped by 800 Megawatts, the  
5 Procurement Proceeding also assumed that more than 1,800  
6 Megawatts of capacity in Southern California would be  
7 retired by 2010. Conventional wisdom at present is that  
8 half of South Bay will be retired. So the entire difference  
9 between the 1,100 Megawatts assumed by the CPUC roughly two  
10 years ago, and the 3,200 Megawatts we see today, can be  
11 explained by those two facts. So going forward to 2016,  
12 compared to 2010, the surplus estimated by staff is only  
13 slightly smaller, 2,900 Megawatts. 2,400 Megawatts in load  
14 growth has been almost entirely offset by 1,000 Megawatts of  
15 new thermal and a 1,700 Megawatt increase in renewable  
16 capacity. And we retired all the South Pad (phonetic) If  
17 we assume that El Segundo complies with the Water Board  
18 policy by retiring prior to the summer of 2015, the surplus  
19 drops to 2,250 Megawatts. These numbers are not surprising  
20 if one recalls that the authorization for what have become  
21 Walnut Creek, El Segundo, and Sentinel, is part of a fleet  
22 replacement policy, that assumes close to 7,000 Megawatts of  
23 retirements by 2016.

24           So what might be wrong with this picture? In many  
25 respects, these numbers are very conservative. The demand

1 response and interruptible load numbers are more than 1,000  
2 Megawatts below numbers submitted by Southern California  
3 Edison and San Diego Gas and Electric to the CPUC and the  
4 Energy Commission within the last year. Thermal additions  
5 are limited to exceptionally high probability projects.  
6 There are no entries for co-generation. One source of risk  
7 here through 2016 is the assumed renewable additions, some  
8 1,150 Megawatts of the 1,743 assumed by 2016. Roughly 290  
9 Megawatts in each of 2013 and 2016 is large scale solar that  
10 Edison and San Diego have already contracted with. This is  
11 a risk. Two days ago, the number on this chart was 300  
12 Megawatts larger, then the Bright Source Project fell  
13 through. So the scale of renewables assumed here is  
14 significantly dependent upon the siting and construction of  
15 large scale solar.

16 We have almost 2,000 Megawatts of new thermal  
17 assumed here. This does not include Walnut Creek, El  
18 Segundo, or El Centro. It includes seven units, only two of  
19 which require approval at the Commission, Canyon and Watson  
20 Co-Gen, Inland Empire 2, if GE is lucky this time, we will  
21 be up before next summer. Riverside should be online by  
22 August, they are in pre-construction. Blythe requires the  
23 completion of a transmission upgrade. Otay Mesa and Orange  
24 Grove are both under construction. So the additions we  
25 assume are very conservative.

1           Now, turning to the LA Basin itself, supply is in  
2 excess of current LCR requirements. We estimate just under  
3 12,000 Megawatts of generation capacity in the LA Local  
4 Reliability Area, that is about 300 Megawatts in the ISO, as  
5 in their LCR studies. All but about 1,200 of this provided  
6 some form of resource adequacy under contracting the summer  
7 of 2009. The 2010 LCR of 9,735 Megawatts taken from the  
8 2010 LCR Study that the ISO did will rise with load growth  
9 and would be expected to follow the transmission upgrades.  
10 This tidy surplus assumes that there are no once-through  
11 cooling policy-induced retirements.

12           Looking at the supply demand balances that were in  
13 the Los Angeles Basin, the three bolded numbers on the top  
14 line were taken from ISF studies, the remaining numbers are  
15 simply the LCR grown at the rate of load growth, as assumed  
16 in the staff's revised 2009 IEPR forecast. The new thermal  
17 are the four plants within the LA Basin. On the list just  
18 shown, Inland Empire, Riverside, Canyon and Watson, the  
19 demand response and interruptible numbers are simply a flat  
20 70 percent of SB 26, the numbers on the previous chart, you  
21 will see that the surpluses are rather substantial, but  
22 unless that number is reduced for yield, we are going to  
23 start talking about why it is not representative of what you  
24 can retire. And you could see what happens to those  
25 surpluses when we begin to implement the State Water Board's

1 policy along a timeline hoped for, El Segundo retiring here  
2 prior to the summer of 2015, its compliance date is the end  
3 of 2015, and then the remaining capacity both in the Basin  
4 and elsewhere, Encino, Ormond Beach, and Mandalay retiring  
5 prior to the summer of 2020. Again, these are pretty  
6 conservative numbers. They do not include a series of  
7 potential supply side resources that you would consider in a  
8 planning context, and that the CPUC will no doubt consider  
9 in their upcoming 2010 Procurement Cycle. One could include  
10 higher levels of renewables. Here, the in-Basin numbers are  
11 primarily Southern California Edison's 500 Megawatt Solar  
12 Project, 1-2 Megawatt rooftop facilities, half under their  
13 ownership, half under contract, but have been approved by  
14 the CPUC. There are a number of things we have not assumed.  
15 We have not assumed the additional wind at the Palm Springs  
16 CREZ, which the CPUC Procurement Proceeding -- the 2008  
17 Procurement Proceeding -- puts at a potential of about 700  
18 Megawatts. We have not assumed the development of in-Basin  
19 solar photovoltaic at rural substations, a potential brought  
20 forth in the current CPUC proceeding. The study  
21 commissioned by the CPUC did not allocate that potential to  
22 in-Basin and out-of-Basin locations. The study itself noted  
23 that it was really a first cut; they needed to look at lot  
24 more closely at the constraints on developing these  
25 projects, so they were not included. And we have not

1 included co-generation. The Energy Commission has  
2 commissioned a report which will be out within the next  
3 couple of weeks, which shows that the in-Basin, including  
4 LADWP, potential for co-generation absent any additional  
5 incentives is on the order of 600 Megawatts through 2019,  
6 and that if one adds such incentives as putting combustion  
7 technologies back into the soft generation incentive  
8 program, providing CO<sub>2</sub> reduction payments to co-generation,  
9 you could increase that number from 600 Megawatts through  
10 about 900, and if you offered incentives for export, you  
11 could get perhaps another 700 megawatts of large co-gen in  
12 the LA Basin, including LADWP. Those numbers have not been  
13 included here.

14           Now the three caveats. The surplus of capacity  
15 in-Basin only indicates that one of the constraints on the  
16 retirement and replacement of OTC capacity might be binding.  
17 There are three others. We have grid stability in Los  
18 Angeles Basin, which requires a commitment of units in  
19 specific sub-areas in the Basin under high load conditions,  
20 basically in Southern California demand increases during the  
21 day, more capacity has to be committed from a set of units  
22 in the LA Basin to meet two constraints, which I will get  
23 into in a minute. There needs to be enough generation  
24 online and unloaded upper blocks (phonetic) available to  
25 provide sufficient inertia that sustain imports, I will talk



1 about that briefly, and I trust that people who follow me  
2 will talk about that, as well, and then the system must have  
3 sufficient ramping capability to absorb intermittent  
4 resources.

5           The sub-LA Basin capacity requirements require the  
6 commitment of increasing amounts of capacity as load  
7 increases in both Orange County and south of Lugo  
8 Substation. The dispatchable capacity cannot be retired in  
9 amounts and at locations that were threatened at being able  
10 to satisfy these constraints. Now, I would really like to  
11 talk in some great detail now about the Orange County  
12 constraint, but you can see I cannot. So I know what the  
13 numbers are under here, but if I started talking about them,  
14 the ISO would beat me to death with a lawyer.

15           COMMISSIONER BYRON: Well, you have others to  
16 contend with, Mr. Vidaver -- why cannot you talk about that?

17           MR. VIDAVER: The ISO actually has three criteria  
18 that documents must meet to be released to the public, and  
19 market sensitivity, system security, and proprietary are  
20 sort of three tests that it has to pass. Perhaps one of the  
21 lawyers that I would be beaten to death with could explain  
22 exactly why this falls under that, and to be honest, I am  
23 not entirely sure. So --

24           The need for inertia in a nutshell, people  
25 following me know far more about this than I do, there must

1 be sufficient generation operating in California to provide  
2 inertia to sustain imports. The amount of inertia that is  
3 necessary is a function of Southern California loads. The  
4 load on major transmission lines into Southern California,  
5 the load on the eastern river, inter-tie, how many units are  
6 on the Palo Verde. The amount of inertia that a given power  
7 plant provides depends on the technology. Unfortunately for  
8 those of us who would like to replace once-through cooled  
9 facilities, the steam turbines provide exceptionally large  
10 amounts of inertia. So if you retire large amounts of steam  
11 turbines, you need to ensure that you have sufficient  
12 inertia being provided by replacement facilities. Solar  
13 photovoltaics do not provide inertia, solar thermal does. I  
14 believe advanced wind does, but some forms of wind do not.  
15 So I am sure this will be covered in far more detail. And,  
16 again, I would show you the ISO operating procedure that  
17 indicates how much generation is needed under various load  
18 conditions in Southern California, but that operating  
19 procedure looks a lot like the one I just showed you, so I  
20 cannot do that.

21           And the finally, the system needs enough ramping  
22 capability to handle the intermittent resources that large  
23 amounts of wind on the system will, in all likelihood,  
24 increase the peak-trough ratio, and the size of the evening  
25 and morning ramps, so you need dispatchable capacity under

1 ISO control, basically, to satisfy loads as they increase  
2 during the day, and fall during the evening. And the  
3 existing steam turbines, in that they are able to operate at  
4 very low load levels, are kind of a natural source of that  
5 ramping capacity. So I imagine the ISO will elaborate on  
6 that. So I think that is it for my presentation. There are  
7 people coming up after me who can probably answer many of  
8 the questions you have far better than I can, but I will  
9 give it a shot.

10 COMMISSIONER BYRON: I was just going to suggest,  
11 you know, you went through so much, so quickly, that you  
12 just go through it all again, a little slower.

13 MR. VIDAVER: I am seven minutes behind. So I  
14 apologize. Well, you really have got to get me out of here.  
15 Give me the hook.

16 COMMISSIONER BYRON: Yeah, but a couple of things  
17 merit some comment, I think. Commissioner, do you have any  
18 comments or questions for David?

19 VICE CHAIR BOYD: Well, I was going to take  
20 David's advice and see if I learned from others what I do  
21 not understand so far, but I am anxious to hear your  
22 questions.

23 COMMISSIONER BYRON: So let's do it that way, but  
24 there are some things that I think need to be clarified, and  
25 I hope others that follow will address some of these issues.

1 Let me state the obvious first. Clearly, the numbers that  
2 you have put up here, the tables of information, there is a  
3 great deal of information, a lot of assumptions involved in  
4 there. I have written down a number of comments as I went  
5 along. We will certainly look for folks to comment with  
6 regard to some of the assumptions that you have made. I  
7 have a question for you. You said Bright Source had a  
8 project fall through, 300 Megawatts. What is that? I had  
9 not heard that.

10 MR. VIDAVER: It is my understanding that Edison  
11 just withdrew the Advice Letter on the Bright Source  
12 Project.

13 COMMISSIONER BYRON: All right, that is fine. We  
14 will let that go. That was one I was not aware of. But  
15 clearly, the economic impact in the Southern California  
16 areas have a dramatic effect on the demand we are seeing, a  
17 little bit of a lag here, but this problem will not go away.  
18 And we do see, despite all our best efforts at energy  
19 efficiency and demand response programs, there is still  
20 growth in the area, and we are going to continue to seek  
21 growth and demand, but there is some lag and -- how can I  
22 say it? I guess there is a silver lining to a declining  
23 economy from an electricity point of view. There is a lot  
24 of information that is contained here. I look forward to  
25 future commenters and presenters addressing those issues

1 that they feel that they can contribute to.

2 I am concerned about one thing, and that is the  
3 comments that you made with regard -- and I know that folks  
4 from the Independent System Operator are here today -- but  
5 comments that some of this information cannot be discussed  
6 or shown for security reasons, or market power or safety, or  
7 whatever, it is extremely important that there be as much  
8 transparency as possible here. We need to convince the  
9 public that we are trustworthy in the evaluation that we are  
10 doing, and just to hide behind these kinds of things as  
11 others in this industry do typically to protect their  
12 customers is not going to cut it; we really do have to think  
13 about getting this information out there and open and in the  
14 public if we are going to get resolution on any of these  
15 issues. So I am not going to hold you responsible for that  
16 yet. But I think, Mr. Vidaver, excellent presentation, and  
17 a lot of material here to digest, but I agree with you,  
18 let's continue. We have many good speakers to go, and if we  
19 do not get these answers, we will come back to you later.

20 MS. KOROSEC: Commissioner Byron, we do have one  
21 question from a WebEx participant if we --

22 COMMISSIONER BYRON: All right, if it is  
23 clarifying question, we will take it.

24 MS. KOROSEC: All right, could we open the line  
25 for Mr. Bruce Rising? Bruce, are you on the line?

1           MR. RISING: Yeah. I was just curious, though,  
2 when you classified renewables, when you had the peaking,  
3 you did a sum of the total supply of Megawatts. Can you  
4 really add the renewables to that capacity? Or has that  
5 been discounted to account for the intermittency?

6           MR. VIDAVER: Big haircut, yeah. It is seriously  
7 discounted.

8           COMMISSIONER BYRON: Yeah, these are peak demand  
9 numbers that you have got on the table. I mean, I would  
10 imagine that wind, in general, does not contribute to  
11 supply.

12          MR. RISING: Okay.

13          MR. VIDAVER: Yeah, I think we actually rated the  
14 solar projects at Edison as generating at about 60 percent  
15 of main play on peak.

16          MR. RISING: Okay.

17          COMMISSIONER BYRON: I think it is fair to say,  
18 the staff has not done the worst case kind of analysis here,  
19 they have tried to be fair in terms of what gets added and  
20 what gets subtracted, but you do have to consider that there  
21 is a lot of variables at play here, a lot of assumptions  
22 that may or may not bear out. All right, thank you for the  
23 question. So we will continue. Mr. Minick from Southern  
24 California Edison.

25          MR. MINICK: Good morning. Unfortunately, I do

1 not think I am going to answer all your questions on how to  
2 solve this particular issue. And bear with me, I am a  
3 generation planner for 30 years at Edison, I am not a  
4 transmission planner, so I can conceptually talk about  
5 inertia, but you need some very very detailed physics people  
6 to talk about exactly how inertia works.

7           COMMISSIONER BYRON: Well, I can appreciate that,  
8 Mr. Minick, but you always give us good information in  
9 presentations and I am glad you are here today.

10           MR. MINICK: Thank you. And I have a clarifying  
11 question that Dave can answer later. On one of his charts,  
12 he showed 10,000 100-Megawatts of imports across the board  
13 in all the years, and I realize that is probably based on  
14 the availability of imports, but, again, that number is tied  
15 to inertia, and I think that could be significantly  
16 downgraded. If the inertia in the LA Basin changes, we  
17 cannot import that much, which would affect that table. And  
18 we will make our comments to you by the October 6<sup>th</sup> time  
19 point on those particular numbers.

20           So defining the need for LA Basin dispatchable  
21 resources is difficult, mainly because we do not know what  
22 the future is going to be in the way of resources, in  
23 general. So let's sort of march through it. The things  
24 that are out there right now, there is an ISO report, and  
25 the ISO can tell you many more details about this particular

1 report. I reference it here because it does exist, they did  
2 a pretty good job, and we are trying to update this report  
3 with the ISO. If you did not know, Edison is working with  
4 the ISO to try to do an intermittent analysis of future  
5 intermittent resources, or higher levels of renewables by  
6 2020 in the 33 percent range. We hope to have the  
7 preliminary estimates done this year. It is a very complex  
8 issue and very difficult to analyze, and we are trying to  
9 sort of stretch the use of production simulation models in  
10 this work right now, so we may have some information before  
11 you later.

12           What the ISO found in their preliminary study was,  
13 is that you kind of meet the needs of the system with 20  
14 percent renewables, with the existing generation or  
15 equivalent amount. So that, in simple, says we think we can  
16 get by with 20 percent if you will leave the units alone,  
17 or, if you take one out, put one in that is about the same  
18 size. Inertia is a little bit different, but that is  
19 basically what they were saying. When we go to higher  
20 levels, we are probably going to need more dispatchable  
21 resources, certainly, because intermittents vary  
22 significantly. We are not sure about the effects on the  
23 system without making significant transmission upgrades, and  
24 we will talk about that later.

25           I think we submitted to you the results of a



1 Nexant study that we did with the other utilities about a  
2 year ago, or six months ago. Again, this was a preliminary  
3 analysis, it did show some revealing information about  
4 higher levels of renewables regarding surplus energy at  
5 certain times of the year. That was pretty good results.  
6 It was not that definitive about how many quick start  
7 ramping resources we needed. So, the number that I show in  
8 here, the 2250, is resultant on we think we can dispatch  
9 these resources enough to respond to intermittency. It did  
10 not look at local reliability problems for transmission  
11 issues. We did not have time in that study to do a detailed  
12 transmission grid assessment of can the grid meet all the  
13 NERC and WECC, and ISO requirements for keeping the grid  
14 stable and safe. So this simply says we think we need some  
15 quick start resources in the future. That is one reason why  
16 we need these new contracts that we have signed, that seem  
17 to be tied up in the PM-10 litigation.

18           The other numbers you see here at the very bottom  
19 of the page are simply extrapolations from the ISO Need  
20 Assessment. The first numbers in 2006 are what the ISO says  
21 they typically need. We took a look at what we thought we  
22 would need in 2025 of 33 percent renewables, based on an  
23 extrapolation of that data. The analysis we are doing right  
24 now should come back with a much more definitive answer  
25 because these ranges are pretty large right now, and we are

1 working on that right now with the ISO.

2 COMMISSIONER BYRON: And, Mr. Minick, just so that  
3 everyone understands what "ramping" means, that is typically  
4 a unit that can be dispatched with known availability that  
5 can ramp up at a certain rate of Megawatts per hour.  
6 Correct?

7 MR. MINICK: Actually it is in a 10-minute period  
8 of time. People bid into the market their ability to ramp  
9 over a 10-minute period of time.

10 COMMISSIONER BYRON: And what kind of generation  
11 qualifies for that?

12 MR. MINICK: Any generation can qualify for that  
13 if they can prove to the ISO that they have that capability.  
14 So hypothetically, take our hydro plants. If they are  
15 running at minimal load, or off, they can typically ramp to  
16 maybe 60 percent of their full load output per minute, so  
17 they can get to full load in two or three minutes, so they  
18 have very good ramping capability. Take a fossil plant --  
19 and we used to own most of the plants that are now owned by  
20 the markets, so I know something about those plants --  
21 typically it is 1 or 2 percent, so if there is a 500  
22 Megawatt project or steam unit, and they are sitting at half  
23 load, so they have some capability to ramp, it is how  
24 quickly can they ramp in a 10-minute period of time. So if  
25 it is 1 percent per minute, that is 5 Megawatts a minute, 10

1 minutes is 50 Megawatts, so that unit sitting at half load  
2 could bid 50 Megawatts into the ramp or ancillary service  
3 markets. That is how much you can provide. Now, a peaker,  
4 if it can start in 10 minutes, could probably bid its entire  
5 amount, so if it is a 100 Megawatt peaker, it can bid in to  
6 the ramping requirements and start, it can be up and running  
7 at full load in 10 minutes, then its full output could be  
8 considered ramping.

9 COMMISSIONER BYRON: And the peaker is the natural  
10 gas units?

11 MR. MINICK: And the peakers are natural gas  
12 units.

13 COMMISSIONER BYRON: Simple cycle natural gas.

14 MR. MINICK: Yeah, typically. Now, we can look at  
15 advance technologies in the future, compressed energy  
16 storage, can we extract it, pumped hydro, batteries, those  
17 are all capable of providing that service, but they are kind  
18 of new and we are still trying to experiment with how they  
19 might be modeled in our models right now.

20 COMMISSIONER BYRON: All right, thanks for the  
21 little diversion there, just to make sure everybody  
22 understands "ramping."

23 MR. MINICK: Now, again, we have talked about  
24 SCIT. SCIT is the Southern California Import Transmission  
25 nomogram, and without showing the chart, it simply says

1 that, when you have different levels of inertia in the LA  
2 Basin, you can import different levels, the higher inertia,  
3 the more you can import. It is imports both from the  
4 Northwest and from the East from Arizona. And you have to  
5 balance the two, and there are limits to how much you can  
6 bring in. As Dave rightly said, old steam plants have  
7 significant amounts of inertia. One of my charts will say  
8 kind of what we are trading off here. The retirement of  
9 older plants and replaced with in-Basin distributed  
10 generation -- photovoltaics, even small co-gens or peakers  
11 -- most likely will reduce your inertia. We have not run  
12 the studies to say, "How much can I import in a future world  
13 with half or all of my OTC plant shut down?" We are going  
14 to be looking at that. Give us a little bit of time and we  
15 will maybe have an answer for you in six months.

16           Importing more renewables from outside the LA  
17 Basin basically is an import; so I just said importing from  
18 the Northwest and importing from Arizona, importing from the  
19 desert is an import, so you are going to want to increase  
20 imports and decrease inertia, the two do not go hand in  
21 hand. It is going to be an interesting, complex thing to  
22 try to solve. As far as local capacity requirements in the  
23 Basin, dispatchable capacity is needed to maintain certain  
24 loadings on certain lines. As you all know, voltage issues  
25 rise all over our transmission system based on how much you

1 are trying to import, what our loads are, and what  
2 generation is there. So if we had some flexible generation  
3 that we can start in the Basin to prop up voltage in places,  
4 that works pretty well. That is sort of our traditional  
5 transmission and generation planning. To change that, we  
6 are going to have to put in new lines, larger capacities,  
7 static bar compensation, and/or batteries or some new way to  
8 do it. We have not even figured out how to do this yet, so  
9 you are sort of way ahead of us saying you want the answer;  
10 we will give you an answer, but it is going to take us  
11 probably a couple of years to figure it out, working with  
12 the ISO, basically, to do that also.

13 COMMISSIONER BYRON: Well, and your brief  
14 explanation there is really good because, I mean, Mr.  
15 Vidaver shows us a table, and everybody can add up numbers,  
16 and it looks real simple. You make some assumptions, you  
17 add in the Megawatts that you are going to add, the ones you  
18 are going to subtract and, hey, what is the problem? But it  
19 is a lot more complicated than that, and it is more  
20 difficult to understand. So even though you have only  
21 scratched the surface there, we can appreciate this, not  
22 just add the numbers up in the table.

23 MR. MINICK: Right, thank you. Well said. Now,  
24 as David showed, these are some assumed additions that he  
25 put in. However, notice the big bold red numbers -- letters

1 beside the units with lower inertia potential -- these units  
2 and some of the notes on there say "near the Arizona  
3 border," inertia at the Arizona border has some value in the  
4 LA Basin, but very little. And once near the Mexico border,  
5 that does not really help the LA Basin a lot, and those are  
6 the two biggest units on there. So we are not getting the  
7 kind of inertia we need with these new replacement  
8 resources. The ones that are retiring are in the Basin, are  
9 large steam turbines, and provide significant amounts of  
10 inertia, so we are going to have to solve this particular  
11 issue.

12           Now, about the PM-10 credits issue, we have four  
13 contracts -- sometimes I say they are three units because  
14 Sentinel was two contracts, we signed some units under the  
15 first contract, we signed with them on some with the second,  
16 the entire plant is close to the 800 Megawatts nameplate  
17 rating, will probably be 750 actual rating. But these are  
18 the units that we need emissions for. So about 1,800  
19 Megawatts here of capacity, located basically within the LA  
20 Basin. The Sentinel plant is in Palm Springs. Some people  
21 do not think that is in the LA Basin, but as far as the AQMD  
22 has assumed, it is in their jurisdiction, so it is actually  
23 considered sort of in-Basin. They are almost exclusively --  
24 the El Segundo Re-power has a little bigger turbine, it is a  
25 combined cycle plant. The others are LMS 100 units, and if

1 you are not familiar with those, they are about a 96-97  
2 Megawatt nameplate rating, under peak load conditions,  
3 probably 93-94 Megawatts a piece. They are small units and,  
4 in essence, have small turbines, and do not provide the same  
5 level of inertia, but they are in the Basin and they will  
6 have some value in popping up voltage and some things like  
7 that.

8           COMMISSIONER BYRON: Now, if you could, just for a  
9 second, I would like to just take a moment and go back and  
10 ask a question -- why did you sign the contracts -- those  
11 four contracts for those four units? What is the basis for  
12 the selection of them? Why do you need that power?

13           MR. MINICK: Okay. In the last LTPP Proceeding at  
14 the CPUC, we looked downstream and the CPUC determined that  
15 we needed some new steel in the ground. There is sort of  
16 two ways of looking at our load requirements, one is a  
17 contractual look, do we have enough contracts to get by and  
18 are there sufficient resources to contract with. The CPUC  
19 determined in that proceeding that we probably needed some  
20 new steel in the future and, again, this is before the great  
21 economic meltdown. And so they said, "We want you to go out  
22 and sign up to a certain level of 1,800-1,900 Megawatts of  
23 new capacity." We went to a new resource solicitation, we  
24 got many bids for that solicitation, and then chose these  
25 resources based on a net present value of the resources that

1 we were basically looking at, and took the ones with the  
2 best net present value to fill that resource need.

3 COMMISSIONER BYRON: Okay, and do you know where  
4 the 1,800-1,900 Megawatt resource requirement came from?

5 MR. MINICK: It came from the LTPP Proceeding, as  
6 directed by the CPUC.

7 COMMISSIONER BYRON: Well, I am trying to get you  
8 to say the Energy Commission because we do the demand  
9 forecast -- we do the demand forecast, of course, that the  
10 PUC relies upon for what is needed in the various service  
11 territories.

12 MR. MINICK: Yes, it was your forecast and it was  
13 some other assumptions on retirements, and I build the  
14 table, so I know what is in the tables. So it was basically  
15 a concerted effort by both regulatory agencies to try to  
16 figure out what at that time we thought was our resource  
17 need.

18 COMMISSIONER BYRON: Now, you mentioned the  
19 economic meltdown, so are these units still needed?

20 MR. MINICK: I guess you are asking me to agree  
21 with David's table. I will not totally disagree, David and  
22 I are friends, and we have worked together a long time. His  
23 assumptions are not totally unreasonable. It is the first  
24 time I have seen it, I am going to have to go back and  
25 dissect it a little more, but I would expect to come to a



1 similar conclusion. I think the driving force behind  
2 building new resources will be the retirement of the once-  
3 through cooling resources, since the timing issue. Where  
4 Dave said they will not retire until the date shown in the  
5 Draft Water Board Policy, I am not sure exactly -- and I am  
6 not an expert on that -- how that policy is going to play  
7 out. Some of those plants could likely retire before that  
8 particular end date, and so I think they will be a driving  
9 force on the availability of those resources to shut down,  
10 but it is also this inertia issue. So if I have to build a  
11 few more resources early to cover an older resource that  
12 retires early, that could also be in play.

13 COMMISSIONER BYRON: Good. Good answer.

14 MR. MINICK: Now, we tried to take a look at this  
15 issue on PM-10 credits is how much do the resources have to  
16 buy, and what do you think they are actually going to  
17 produce. So we tried to do some modeling, and I have  
18 already been warned by my staff at Edison that I said we  
19 used our own internal load forecasts, so let me say, it is  
20 not something hidden, I simply used what was called Edison's  
21 spring forecast this year, it is slightly higher than our  
22 September forecast that you have all seen, I think, this  
23 week possibly, so it is not a terrible forecast, it is a  
24 little bit higher than, I think, the CEC's, and our current  
25 forecast, but it is in the ballpark. The purpose for this

1 analysis -- and this is not to say it is absolutely right,  
2 it is to try and say how do we think these resources might  
3 be run on our system, so we did look at all these factors,  
4 we updated some RPS assumptions throughout the WECC, so we  
5 raised some requirements in other states, so they built some  
6 renewable resources, so in many cases building more  
7 renewable resources in other states simply mean other states  
8 are generating more power, and we might have less imports,  
9 or we might use our own resources less because there is  
10 surplus in the market. So we used a model that many people  
11 have used we used a WECC-wide, meaning we dispatched the  
12 entire WECC to see how these resources might be dispatched  
13 under market conditions in the entire WECC. We did not shut  
14 down a significant amount of once-through cooling plants.  
15 You will see here, we said about 3,000 Megawatts by 2020,  
16 this is about half of what is actually out there, but we did  
17 not think we could necessarily assume they could all be shut  
18 down forever, or should another reason, so these are the  
19 assumptions we used.

20           And the next page sort of tells you how these  
21 plants were operated. And, again, this is just a one  
22 snapshot look. I do not expect these numbers to change  
23 radically because these are peakers and there are lots of  
24 energy and resources out there to import as long as we have  
25 in the inertia to import it. So what you see here is modest

1 capacity factors for some of these resources, around 20  
2 percent max, and you will see that the PM-10 equivalent  
3 offsets that we typically need, if we said that we can  
4 perfectly forecast our offsets, are about 670 pounds. Based  
5 on what the rules are, if they do not want to be restricted  
6 in their operations, they are going to need to buy about  
7 2,000 pounds. So there is a significant difference between  
8 what they need to buy under the regulations, and I am not an  
9 expert on regulations, but we can talk to the AQMD if you  
10 want to get into the details of that, I just have been told  
11 by my people that that is about what they are going to have  
12 to buy. But they are only going to produce 670 pounds.

13           Now, what do we need to do to determine future  
14 resource needs? A whole bunch of things. We need to do  
15 resource planning studies changing the RPS scenarios, the  
16 type and the locations of different RPS resources, how much  
17 is geothermal, how much is solar, what kind of solar,  
18 whether it is solar thermal, as Dave said, solar thermal  
19 gives you some inertia, solar PV does not give you any  
20 inertia. We have got to look at changing load growth and  
21 electrification and DG, meaning how much in-Basin generation  
22 will be built, how much is CHP, how much is solar.  
23 Electrification is a big driver because that is going to  
24 raise our load in the Basin. We are just starting to do  
25 these things. I would expect to have us do a lot of these

1 studies in the LTPP Proceeding next year. I expect there is  
2 probably going to be multiple scenarios, meaning probably at  
3 least three, four, or five different scenarios, with  
4 different sensitivities with some of these variables. All  
5 of those will give us a slightly different answer, so we  
6 will have a pretty good range of what might be expected. To  
7 date, the LTPP has not done transmission planning. In this  
8 particular LTPP proceeding, we are probably going to start  
9 doing much more rigorous transmission planning as part of  
10 the overall process. We are going to have some voltage for  
11 instability and other violations from WECC and their  
12 standards, so we are going to have to take a strong look at  
13 exactly what is happening under these cases and seeing if we  
14 can find transmission solutions to make the grid work. And  
15 then, also, we have good operability studies which means how  
16 much ramping do I need, how many ancillary services, can  
17 they cover ramps, can they cover contingencies and operating  
18 issues. That has all got to be studied. We are starting  
19 now. I look at it to be a year or two of significant  
20 studies with us, your staff, the ISO, and many other parties  
21 that are probably going to get involved.

22           So the conclusions are, we cannot tell you right  
23 now how, what the dispatchable needs are and the in-Basin  
24 needs are to make the system work. We have started the  
25 first phase of this ISO study, I think they will probably be

1 doing a Phase 3 next year getting into more detail. We do  
2 know the LA Basin needs some inertia to import, we know we  
3 need to import either from out-of-state, or just the  
4 renewables that are in the desert, so if we do not have  
5 enough inertia, we are going to have to find transmission  
6 fixes, and right now I cannot say we have identified or  
7 solved all those transmission fixes. And then we have to do  
8 significant transmission planning to figure out what the  
9 grid needs to be, and how robust it needs to be, to be able  
10 to import all this renewable power, or use distributed  
11 generation in the LA Basin to solve some of the load issues.

12           COMMISSIONER BYRON: One question. This has to do  
13 with this fact that we are all joined here by a number of  
14 issues, including once-through cooling, this prior reserve  
15 issue, as you know, as I mentioned earlier, the State Water  
16 Resource Control Board is going to promulgate their rule,  
17 they indicate, by the end of this year; none of us is an  
18 expert on what that will end up being. But we are going to  
19 need to work closely together in terms of how we figure this  
20 out. You have got a lot of analytical capability, a lot of  
21 information that is included in these studies that you will  
22 be doing. Maybe you are not the right person to answer this  
23 question -- will you share that information? Can we have  
24 access to that, so we can evaluate it and do this in a  
25 transparent way?

1           MR. MINICK: Absolutely. Everything we are doing,  
2 I see very little that will be held back. I agree with Dave  
3 that there are certain ISO operating procedures that have to  
4 be kept confidential, but all our results will be made  
5 public.

6           COMMISSIONER BYRON: Good. And more than results,  
7 I think we need to really -- our staff needs to be able to  
8 dissect, if you will, a lot of the assumptions that are  
9 involved. As you indicated, you may use a different demand  
10 than we use, so I think I am asking, really, will you open  
11 up the books so that we can see the assumptions, not just  
12 the results that go into this kind of analysis.

13          MR. MINICK: Absolutely, unless I am in violation  
14 of some confidentiality issue with the ISO.

15          COMMISSIONER BYRON: Well, and these  
16 confidentiality issues, I think it is incumbent upon us as  
17 state agencies, and even the Independent System Operator, to  
18 make the case for why something is confidential. It is just  
19 not acceptable to say it is a national security issue, but  
20 that is not your problem.

21          MR. MINICK: Right.

22          COMMISSIONER BYRON: Mr. Minick has always very  
23 informative, a lot of information, short period of time.  
24 Will you be here for the rest of the day?

25          MR. MINICK: Yes. I am on the panel.

1           COMMISSIONER BYRON: Good, because I am hopeful  
2 that others will have good questions for you. Commissioner,  
3 do you have any questions?

4           VICE CHAIR BOYD: No, thank you.

5           COMMISSIONER BYRON: Thank you. Ms. Korosec.

6           MS. KOROSEC: We do have a couple of questions on  
7 the WebEx. First, again, from Bruce Rising. Can you open  
8 his line for us?

9           COMMISSIONER BYRON: Mr. Rising, go ahead, but we  
10 are really looking for clarification, I think, at this  
11 point.

12          MR. RISING: Yeah, I am looking for the definition  
13 of the term inertia. Is that another way of describing  
14 voltage support?

15          COMMISSIONER BYRON: Good question, good question.

16          MR. MINICK: It is not just voltage support. And,  
17 again, I am not a transmission planner. Inertia gives your  
18 system the ability to respond to electrical disturbances on  
19 the system, equipped enough so that you do not lose the  
20 whole system when it goes down. So it is actually bars, how  
21 many bars can you provide into the system.

22          MR. RISING: Are you using the existing  
23 infrastructure? Are you running those units -- like the  
24 Scattergood and Haynes, with synchronous condensers, at  
25 times?

1           MR. MINICK: No, I am not running anything as a  
2 synchronous unit. That might be one option is to convert  
3 old steam plants to synchronous condensers. That could be a  
4 solution to some of the issues.

5           MR. RISING: Okay. Thank you.

6           MS. KOROSK: The other question is from a  
7 gentleman who is not on the phone, but I will read the  
8 question here that he sent in. "Why did we need contracts  
9 for Blythe and Otay Mesa then? Aren't we paying too much  
10 under contracts for these projects since the financial  
11 market collapse?"

12           MR. MINICK: Well, first, the Otay Mesa contract  
13 is not an Edison contract, so I would prefer to not answer  
14 questions about that one. The Blythe contract, in essence,  
15 was the lowest cost option in our solicitation, so we think  
16 that is one of the more cost effective resources that we  
17 could have purchased.

18           COMMISSIONER BYRON: I think we have one more  
19 question? All right, thank you very much.

20           VICE CHAIR BOYD: Yes, thank you. Very  
21 informative.

22           COMMISSIONER BYRON: I believe the next presenter  
23 is Catalin Micsa from California Independent System  
24 Operator.

25           MR. MICSA: Good morning, everybody. My name is



1 Catalin Micsa. Good morning, Commissioners.

2 COMMISSIONER BYRON: Good morning.

3 MR. MICSA: I am here mostly to talk about these  
4 location and capacity requirements for the LA Basin in the  
5 ISO controlled area. I can try to address some of the other  
6 questions there were here before. I apologize, I cannot do  
7 anything about some of our operating procedures. They had  
8 been hardly reviewed by legal, FERC, and other entities, and  
9 they are divided in, some of them, on market and they are  
10 posted on our websites. If they have an "M" number, they  
11 are market, and anybody can see what is out there; for  
12 example, Southern California Import Transmission, SCIT, it  
13 has market pieces, you can go look on the ISO website what  
14 it is about, and there are some other pieces of it that are  
15 market sensitive, and we are just not publishing out there  
16 now. Here, the way I looked, this is an ongoing process and  
17 we are looking many years ahead, and once we do some more  
18 studies, we probably are going to be able to make those  
19 results available to the public. What is really market  
20 sensitive is what is building right now because, you know,  
21 the generators and the load they are bidding day in and day  
22 out, and that is market sensitive. To me, it is nothing  
23 that you want to do 10 years from now, it is not really that  
24 market sensitive. So once we start doing some more of those  
25 studies, I am sure that we can probably release some of the

1 results.

2 COMMISSIONER BYRON: Yeah, Mr. Micsa, I do not  
3 want to be misunderstood, either. We are not accusing  
4 anybody of hiding the football. I am really interested in  
5 making sure that the public, if it is not completely  
6 transparent, they understand why information is not being  
7 released about an operating procedure or market sensitive  
8 information. And I am just saying, we have the obligation  
9 to make that explanation.

10 MR. MICSA: Right, and we are replying that, once  
11 we go through more workshops, I am sure we are going to have  
12 some more next year and the year after that, in how do we  
13 implement, you know, the shutdown of the once-through  
14 cooling, if that is what people want to do, because  
15 personally I would really like to see how the generation  
16 community responds to what the Water Board put out there and  
17 how they want to comply with that, for us to be able to make  
18 a plan --

19 COMMISSIONER BYRON: Yes.

20 MR. MICSA: -- a scheduled plan of implementation.  
21 So we are going to have some more discussions in the next  
22 couple of years. Personally, I just do not want to get into  
23 a situation -- it looks like right now there is some ruling  
24 in LA Basin, at least to have a plan to achieve a goal. I  
25 do not want to get into a situation like I had today, for

1 example, in San Francisco, or San Diego, where we are  
2 fighting for every 10, or 50, or 100 Megawatts in order to  
3 keep the NERC mandatory standards in compliance, and stuff  
4 like that, so trying to avoid that by being proactive and  
5 having a heads up approach to how to deal with all these  
6 issues together. There are many issues, not a single one,  
7 as you pointed out.

8 I would like to just briefly talk a little bit  
9 about research adequacy and how this fits in. Basically  
10 that gives us resources available when and where needed,  
11 they have to be under contract. Most of you already noticed  
12 the generator usually makes a showing in the month ahead  
13 with 100 percent of what the procurement is in a year had to  
14 make 90 percent system and 100 percent local. They all have  
15 a must offer obligation to the ISO. The problem is, if we  
16 do not have our contracts, the units we usually do not have,  
17 we do not have FERC must offer anymore, the ISO, so they are  
18 not really obligated to bid into the ISO market, it can just  
19 shut down the unit and we will not be able to dispatch it.

20 What is the ISO ruling here? We do the review of  
21 these bodies to make sure that all the existing fleet and a  
22 new fleet coming up gets deliverable to the aggregate of  
23 loads, so basically it has an opportunity to exit the pocket  
24 they are on, and get into the main heart of the grid. Also,  
25 we look at the locational capacity requirement based on our

1 FERC approved tariff. We do all the studies regarding the  
2 location of capacity, and we actually allocate the  
3 responsibility of that to the load serving entities, and  
4 then it is their choice if they go buy it or not, and we do  
5 have a backstop procurement if not enough capacity is made  
6 available in these local areas. More so, we also do the RA  
7 import allocation, basically we allocate imports coming into  
8 the ISO control area based on FERC approved tariff. And, of  
9 course, we ultimately do the operation of the grid.

10           The Resource adequacy procurement, you can see  
11 that on the bottom, usually the way we think about it is you  
12 need some local resources in order to reliably operate the  
13 system based on the NERC, WECC, and ISO standards. Then,  
14 beyond that, you can pretty much buy any units you want,  
15 anywhere in the system, and those are very flexible and you  
16 can just buy for one month, or whatever. The imports are  
17 allocated, again, based on our methodology, and we also have  
18 the minimum locational capacity, so basically the ISO mostly  
19 does this portion over here, and this portion over here.  
20 And the state and other local regulatory agencies, they do  
21 this portion over here.

22           What are the local capacity requirements? It is  
23 basically we have this local area, it is very limited on  
24 what you can import in. When I am saying "very limited,"  
25 you cannot import enough to serve all the load, you have to

1 have some local generation in order to meet the standards.  
2 Now, the way we do the study is we have a 1 or 10 peak, so  
3 it is basically a summer or super hot peak, we will maximize  
4 the transmission coming into the area. We assume everything  
5 is in service, and then we take the required contingencies,  
6 but basically everything is available to us, and then we  
7 just -- we give out the number of minimum local resources  
8 that need to be purchased in order to meet that. And the  
9 assumption is that all of those resources will be available,  
10 so, again, 100 percent of those resources will be available  
11 to the ISO.

12                 Currently, there are two local areas across the  
13 ISO grid, as I said, in Northern California, and through the  
14 Southern California. The LA Basin is the biggest local  
15 area.

16                 COMMISSIONER BYRON: Excuse me, just a quick  
17 question. So when you say you maximize transmission imports  
18 in your analysis, is that pretty much the number from the  
19 table that Mr. Vidaver had? He showed about 10,100 Megawatt  
20 net imports, so are you assuming a larger --

21                 MR. MICSA: In essence, that assumes about the  
22 same thing, but we are talking about two different issues  
23 here, the data put out there is regarding to the Southern  
24 California import transmission, is the entire Southern  
25 California. Let me refer to this map. It is something on

1 this magnitude over here, something like this, it is the  
2 entire Southern California. Mostly what we do in the  
3 locational capacity, we go on smaller areas than that and we  
4 have defined -- the LA Basin is defined with this black  
5 marker over here, and then we have Big Creek, Ventura area  
6 that is somewhat defined as this area over here, we also  
7 have San Diego, which is just down here, these outskirts, as  
8 local areas. If you think about them, they are smaller  
9 areas inside the big system.

10 COMMISSIONER BYRON: Right, more discreet.

11 MR. MICSA: More discreet.

12 COMMISSIONER BYRON: And, as usual, always more  
13 complicated than a simple table indicates.

14 MR. MICSA: Usually, yes. So our defined  
15 elevation, you pretty much have this black oval over here.  
16 We do have -- most of our requirements are kind of split in  
17 two and you have got to see from -- there are slides I have  
18 in the future here that there will be differences in  
19 requirements between the western part, which is this part  
20 over here, we consider that as being the western part, and  
21 we consider this area over here to be eastern part. They  
22 are cut somewhere around here. I am not going to stop much  
23 here. The 20,000 Megawatts is about this local area, it is  
24 a humongous local area. Available resources to date are  
25 close to about 12,000 Megawatts or so. You have the worst

1 contingencies in the western pocket, which is close to 5,000  
2 that we have for 2010. The overall -- what is important  
3 here is the overall LA Basin is close to 10,000 Megawatts  
4 that are needed in that area. So under the 12,000, we need  
5 about 10,000 currently. This is in 2010 studies. Now, this  
6 is 2011 -- 13,000 -- we looked out five years, you can see  
7 the load is growing up a little bit. The resources assumed  
8 that we will be growing up. Of course, some of those new  
9 resources that were assumed in there require new air  
10 permits. Also, it is important to note that, in our future  
11 studies, we do have some transmission. We did model Palo  
12 Verde-Devers 2, that one, as we all know, got stalled for  
13 now. Rancho Vista is moving far along. And the Tehachapi  
14 project is moving far along. The Vincent-Mira Loma is part  
15 of the Tehachapi, so we expect that to be done around 2013  
16 timeframe. You know, LADWP can speak for their Green Path  
17 and Norton, what situation that one is on.

18           If you consider this project as being available,  
19 then if you look to the future, you can see that the western  
20 area requirements actually is going up every year. It goes  
21 from 5,000 to 6,000, and it goes to 8,000. Now, you can ask  
22 yourself, that is a tremendous increase in number, first it  
23 is below growth, we do not disagree with that. And there is  
24 a good reason for that. The reason is the LA Basin overall  
25 is decreasing, and you can say, "Well, what is going on

1 here?" So I am going to explain a little bit about this.  
2 You can see in 2011, it is 10,000 Megawatts, and all of a  
3 sudden what we are saying is that basically what is going to  
4 be left after that will probably be this 8,500 over here.  
5 Now, what is happening is these approved projects that we  
6 have over here, for example, some of the major projects that  
7 are allowing us to import more power into the LA Basin, Palo  
8 Verde-Devers 2, yes, but most importantly, Vincent-Mira Loma  
9 500 kV, and even Green Path. What this project is doing is  
10 actually, the way it was approved by the California Public  
11 Utilities Commission, is taking some of the old 230 kV lines  
12 and they are operating them to 500. Now, once you do that,  
13 you increase the entire imports for the LA Basin, so those  
14 are -- the requirements are dropping significantly because  
15 you are bringing in new 500 kV line. But I can probably  
16 explain better in this drawing right here, so what is  
17 happening is we have a new line that is coming down, a new  
18 500 kV line that is coming down this way, but once it  
19 reaches this area over here, it is very hard to permit new  
20 500 kV lines, as we all know. They are taking pieces of the  
21 old 230 kV equipment and they are operating it to 500, and  
22 now all of a sudden you have got a lot more import  
23 capability in the entire LA Basin, but by the same token,  
24 because you took those 230 kV lines out, you have decreased  
25 the imports into the Western LA Basin. So basically, the



1 reason why everything is dropping is mostly because of these  
2 transmission projects, and the reason why the Western LA  
3 Basin is increasing is because of the same projects, because  
4 they are taking lines out and we do not have them anymore.

5 COMMISSIONER BYRON: I am a little confused by  
6 that. You are taking lines out. That is not correct. You  
7 are doubling the capacity of those lines.

8 MR. MICSA: That is correct, but it does -- so  
9 overall, there is a great benefit because you see we are  
10 going from a requirement of, you know, 10,000, then in 2011  
11 we go a little bit beyond 10,000, and all of a sudden the LA  
12 Basin decreases to below Western, so really the overall  
13 numbers are going down. If you look from an overall  
14 perspective, the number is going down from 10,000 to 8,500.  
15 Because, really, the eastern area will probably have close  
16 to no requirements, okay? So if you look from this map over  
17 here, we are increasing the overall import into this whole  
18 area, but by taking transmission out of this sub-area, this  
19 sub-area becomes even more constrained than before, so the  
20 requirements for this sub-area is going up, and at the same  
21 time, the requirements for the entire LA Basin is going  
22 down. The net effect is that everything goes down. It goes  
23 down from 10,000 to 8,500, so we are doing a good thing  
24 here, we are saving 1,500 Megawatts of local generation.  
25 Except, today that can be met from either East or West.

1 Tomorrow, all of that has to be met from the West because we  
2 just took those lines out and we need to rely heavily on the  
3 western guys versus the side.

4 COMMISSIONER BYRON: It sounds like we are making  
5 a mistake.

6 MR. MICSA: Overall, it is not a mistake, but just  
7 -- if you look from a Western area LA Basin perspective, it  
8 is a mistake. Now, there are some other projects --

9 COMMISSIONER BYRON: Well, that is not -- because  
10 in the west is where we have all the once-through cooling  
11 plants.

12 MR. MICSA: So if you look from the once-through  
13 cooling perspective, it is a mistake. But if you look from  
14 an overall local capacity perspective, it is a benefit.  
15 Now, let me just go a few more slides here because we do  
16 have more projects beyond that. I am going to come back and  
17 talk about this, but if you look further down the road, we  
18 just finished these studies about two weeks ago, and we  
19 published on September 15 on the ISO website. There are  
20 some additional projects beyond those that we start in 2013,  
21 and they are supposed to be coming in 2014 or so timeframe.  
22 Some of the remaining lines are getting re-conducted, so  
23 once you do the next phase, that 8,500 Megawatts, it is  
24 going down again, it is going down to 6,700. See, we  
25 started around 5,000 for the West, then we went to about

1 6,000, then to about 8,000, and the next year we go down to  
2 about 6,700. Additional projects are needed beyond this to  
3 decrease this number further. Today, we do not have anymore  
4 projects that are approved. We are working with Southern  
5 California Edison and all the market participants to see  
6 what additional projects might be needed beyond that.

7           Okay, so I would just like to talk a little about  
8 the real time operations. We go and we define all these  
9 local areas, and then that is the minimum generation that  
10 needs to be purchased in that local area. Now, how you  
11 actually dispatch those units in real time is a combination  
12 of things. We use security constrained OPF and basically  
13 the least cost generation comes online given that we need to  
14 comply with all the transmission constraints. Now, when you  
15 say, well, what are the minimum daily constraints, and Mark  
16 had a table here, and David tried to put up there, and it  
17 said it is market sensitive and we cannot really put it up  
18 there. Basically, it is driven by a low forecast, it is  
19 driven by transmission generation out-of-service. We do not  
20 have 100 percent availability of every equipment in that  
21 area at all times, so it depends on which ones are available  
22 at any given point in time. Also, as we talked before, it  
23 is very important that they actually get those imports. We  
24 talked about the 10,100 number, that is for the entire  
25 Southern California coming in, and that nomogram -- it has a

1 inertia component, and when you think about inertia, think  
2 about it as a relation of mostly mass, you know, how big the  
3 generator. Yes, technology has a lot to do with it, too,  
4 but just a short assumption is, the bigger the generator,  
5 the more mass it has, the bigger the inertia, and it is very  
6 important that we have inertia to allow for the imports to  
7 come in from Arizona, or Northern California, or some of  
8 these remote areas it has to come in to the Los Angeles  
9 Basin. It is important that you have inertia, and it is  
10 available.

11           Now, if you are talking, "Can we actually just  
12 replace that with peakers?" Because I have heard people  
13 asking about it, well, we see some of these existing  
14 generators that have a very low -- not an availability  
15 factor, because the availability factor is very high, but  
16 actually how much they run. They do not run that many  
17 hours. So why don't we just replace them with peakers?  
18 Well, for one, it is not the same thing. Inertia is a  
19 really big driver. We tried to replace with peakers, we  
20 have small or renewables which have most of the neglectable  
21 inertia. We are going to need a lot more generation than we  
22 are retiring, so, you know, we do not know what that "a lot  
23 more" is right now, but it is probably five times the  
24 amount, we do not know what that is because we just have not  
25 done the studies. We will be doing some more studies, one

1 for ramping -- we talked about ramping -- we are going to do  
2 some ramping studies for renewable integration for 33  
3 percent. I believe by the end of the year, we will be able  
4 to publish a report on that. And that will just mostly deal  
5 with the ramping issues. We have not tackled yet the  
6 inertia issues, we probably will tackle that next year in  
7 our next assessment, so we can give you a better picture  
8 about the inertia issues.

9           The transmission system, it is very dynamic, with  
10 a lot of unexpected twists and turns. Also, the existing  
11 fleet, it is permitted to run year-round. Yeah, they are  
12 not running that much, but it is permitted to run. So the  
13 new peakers that we see coming out, most of them have a very  
14 limited number of hours, permits run, I do not know, maybe  
15 500, 1000 hours a year. Well, you know, if something  
16 happens and Diablo goes out for a month to be refueled, you  
17 can burn out more than 500 hours on a peaker in one month,  
18 and then what do you do for the rest of the year? So we  
19 might need to permit a lot more peakers in order to cover  
20 more time of the year because each one of them will be  
21 permitted for less number of hours. Well, if you do that,  
22 my personal opinion, you just spend a lot more money in  
23 putting a lot of these on that have smaller amounts of time  
24 that they can run, so probably it is advisable that we use  
25 some base loaded plants, more like combined cycle, something

1 that are permitted to run more hours, even though, if they  
2 do not run, and they do not put any NO<sub>x</sub> emissions in the air,  
3 well, great, but at least they should have the flexibility  
4 to be available because otherwise we can run into some  
5 troubles and we do not want to get into low shutting.

6 COMMISSIONER BYRON: Well, that is great from an  
7 operator's perspective, but having the Emission Reduction  
8 Credits is really the issue that we are dealing with.

9 MR. MICSA: Right, and I do not know how to make  
10 those available, that is why we are all here, to talk about  
11 all the issues we have. I am just hoping that we can make a  
12 plan to go from where we are today to where we want to end  
13 up five, six years from now, and that we can meet all of the  
14 standards without violating the ones that we are here to  
15 speak for, which is the mandatory NERC standards. But we  
16 understand, you know, the once-through cooling issues, we  
17 understand the air permitting issues, we understand all this  
18 stuff, and we are trying to work with everybody to achieve  
19 all of their goals. The only reason we are here is that we  
20 can plan -- allow us the time to plan and tell us all the  
21 requirements that you would like to see, and some of these  
22 are brand new, you know, like the once-through cooling,  
23 bringing in requirements, even the staff in California Air  
24 Quality District, who are there for a long time, they just,  
25 you know, because of the loss, like you said, the loss and

1 that other thing that happened here, they are new  
2 developments. As long as the new developments allow us the  
3 time to plan, I think we can do a pretty good job of that.

4 So in conclusion, from a local capacity  
5 perspective, we see the long term that the LA Basin will  
6 most likely we illuminated the way you know it today. We  
7 will form two new local areas, one will be called Western  
8 and one will be called Eastern LA Basin. From what we can  
9 tell today, all the resources that will be connected to  
10 Devers, and there are a lot of renewables connected to  
11 Devers, it goes through Palm Springs, and those will be  
12 outside of the local area. Upgrades west of Devers are  
13 expected, you know, we fully expect that we are going to see  
14 some of that. Also, beyond that, as you said, our biggest  
15 problem, like you acknowledged, Commissioner, is the Western  
16 LA Basin, and that will require new resources, and I do not  
17 know how to get around the permits for those, or new 500 230  
18 kV transmission projects, and we are saying we are expecting  
19 at least two or three new 500 kV lines in the area, you  
20 cannot just build one because if you lose it, you are back  
21 where you used to be, so you need at least two or three to  
22 account for contingencies. That is not easy to permit  
23 through that area because it is densely populated, too.  
24 There is no silver bullet here, we did not come with a  
25 silver bullet today, we acknowledge there are all these

1 balls in the air, and somehow we are going to need to plan  
2 to meet them all, and we are here to play and get the  
3 planning going. We expect that, you know, all of these can  
4 be met somehow, we just need to reach the conclusion how,  
5 and to be able to plan them along. I always say I would  
6 like to see -- all the generators like to complain -- to see  
7 the plans from the generation community, how they are  
8 planning to comply with the Water Board regulations for us  
9 to be able to plan because we cannot allow our plan to shut  
10 down first. The preference should be given to power plants  
11 who want to repower. If somebody wants to repower and they  
12 want to go and destroy the site and rebuild on the same  
13 site, they should get priority of shutting down first,  
14 versus I shut down and it is not really permanent, because  
15 if I shut down somebody permanently, I cannot allow the  
16 other person to shut down to meet and we will decide because  
17 it takes longer than one year and we have to go through at  
18 least one summer. So priority needs to be given to people  
19 who would like to repower versus people who would like to  
20 shut down. That is why I say it is very important that we  
21 plan these things out through the years, how to reach  
22 compliance with not just the Water, but the Air Quality  
23 Emissions and all that stuff. If anybody has any questions.

24 COMMISSIONER BYRON: Very good. Thank you. I am  
25 glad you are here. A lot of information. Dr. Jaske, I am



1 glad you stepped up because my singular question is to you,  
2 and to Mr. Vidaver, and to staff. I find this very  
3 complicated. I do not understand everything in this  
4 presentation. Have you digested this recent ISO study? Do  
5 you understand all this material?

6 DR. JASKE: I understand what he is saying, I do  
7 not think I understand all of the steps he has gone through  
8 to get to his conclusion. So, as you observed earlier, we  
9 will be at this for quite a while, and our various speakers  
10 so far this morning have indicated that some of what they  
11 are talking about is preliminary and needs more study. And  
12 if there is going to be any refrain throughout this day,  
13 probably, it is that we need more study. And the analytic  
14 side of the industry has not yet done all it needs to bring  
15 forward to the decision makers the choices. That is still a  
16 ways off.

17 COMMISSIONER BYRON: It kind of -- yeah,  
18 Commissioner Boyd is whispering here, too, it does make it a  
19 little difficult for us to public recommendations in an  
20 Integrated Energy Policy Report.

21 DR. JASKE: I believe Ms. Korosec said it  
22 correctly. This IEPR will be able to give a status report  
23 and frame the issue, it is not going to solve it.

24 I do have a question for Mr. Micsa, which is why I  
25 came up here. Could you show slide 17, please? An

1 important point you made about slide 17 is that the Western  
2 LA number in 2020 goes down to 6,700 or thereabouts. And  
3 you said that was a result of the transmission system  
4 upgrades on the previous slide 16. And I thought I heard  
5 you say, but it is not written down, that you expected some  
6 of those projects to actually become operational before  
7 2020. Did I hear you correctly?

8 MR. MICSA: Well, these projects are actually  
9 supposed to be operational in 2014 and 2015 timeframe.

10 DR. JASKE: And so my basic question is, has the  
11 ISO sort of done a year by year analysis that shows when  
12 that sort of the schedule on which the Western LA Basin  
13 number diminishes as either individual or groups of these  
14 transmission lines come in to service?

15 MR. MICSA: We already have the results for 2010,  
16 2011, 2013 and this long-term one. We are working right now  
17 on 2012 and 2014. So before the end of this year, we will  
18 have '10, '11, '12, '13, and '14, for sure, and we actually  
19 have a vision for 2020. So I think we have quite a lot of  
20 numbers to look at from a locational capacity perspective.

21 DR. JASKE: Okay, but from an OTC power plant  
22 retirement scheduling process, it is knowing when those  
23 transmission upgrades happen that allows the timing for the  
24 retirement or the down time for repowering for those OTC  
25 facilities.

1           MR. MICSA: That is very very correct, so the  
2 timing of the transmission projects and the timing of the  
3 generation proposals to repower versus retire is very very  
4 important, and we have most of the timelines for the  
5 transmission. These are all approved projects that we are  
6 talking about. For these ones, we do have all the  
7 timelines, and we can write it down for you if you want to.  
8 What we do not have right now is we do not have the other  
9 equation about what the generation community wants to do,  
10 and we would like to see that so that we can put the two  
11 together and have a master plan, of how to get from here to  
12 there.

13           DR. JASKE: Well, but also there is a perspective  
14 of having the transmission plan, or the ability to move  
15 transmission projects around so as to influence what the  
16 generators want to do.

17           MR. MICSA: That is correct. And once we are  
18 going to have both sides of this integration, we can put  
19 them together and see if we need to get some projects done  
20 faster, or we should postpone certain generation  
21 retirements, and whatnot, in order to accommodate all the  
22 schedules. I am not saying it is going to be easy, I am  
23 just saying some of these transmission lines are approved,  
24 some of them are just approved by the ISO, but then maybe  
25 the routing is not approved at the PUC, so we need to all

1 coordinate between the California Energy Commission, the  
2 ISO, and the CPUC, how to get the plant going.

3 DR. JASKE: Right. Thank you.

4 COMMISSIONER BYRON: You know, if it were just  
5 those two factors, balancing the generation and the  
6 transmission side of this equation, I think we could figure  
7 it out easily. But, as we know, there are a lot of other  
8 factors involved here.

9 MR. MICSA: There are a lot of factors, and we  
10 will have some response for you regarding the ramping needs,  
11 especially for 33 percent integration, by the end of the  
12 year. Now, we have not started yet on inertia. We are  
13 planning to do that in the next planning cycle, which is  
14 next year. That is all we can do.

15 COMMISSIONER BYRON: Absolutely. Mr. Micsa, it is  
16 great to have you here, to have a transmission planner from  
17 the ISO, very valuable to get into the technical details. I  
18 can also tell you, at the highest levels in the  
19 organization, we are working closely with the PUC and the  
20 ISO to address all of these issues in a more substantial  
21 way, particularly around the once-through cooling concern.  
22 It is not just going to be a transmission fix or a  
23 repowering fix, there is a lot more involved in all this.  
24 So we look forward to your analysis, I hope you will be as  
25 forthcoming with the information as you can, again, for a

1 lot of the same reasons we were discussing around  
2 transparency, but also for our staff to be able to evaluate  
3 all this information as sort of, if you will, the balancing  
4 organization around the environmental transmission  
5 generation issues. Sir, would you like to identify  
6 yourself?

7 MR. TURNER: Sure. Mark Turner with Competitive  
8 Power Ventures. I have got a clarifying question for slide  
9 15. When you mentioned that the peakers usually have higher  
10 energy costs and/or are more polluting when they are  
11 operating, my understanding is that, you know, the peakers  
12 that are coming online have intermediate type peak rates,  
13 they are extremely more efficient than the boilers that are  
14 existing on the coast. And, in addition to that, in order  
15 for the boilers on the coast to provide the services that  
16 they are now providing, they were not really designed to do  
17 that, they are not able to come up in 10 minutes like the  
18 new peakers do to provide the ramping service. They are  
19 needed to come online on a day-ahead basis, so they are  
20 basically left on during the night in order to provide those  
21 services. So I do not know if that fits in with your last  
22 bullet?

23 MR. MICSA: Our ramp rate was not -- I apologize  
24 for the wording here -- but we did not really mean to  
25 compare the new peakers with the existing fleet. We meant

1 to compare with the new peakers versus new more like base  
2 loaded, so new versus new, not new versus old. You compare  
3 old versus old and new versus new. We are not trying to  
4 compare new versus old. So if you just look from that  
5 perspective, probably a new peaker, probably that is true,  
6 but we make it easy.

7 MR. TURNER: So as I understand it, the  
8 opportunity cost is, you know, what you need is new ramping  
9 resources that come up quickly. So that is the services  
10 that the OTC units are providing now, and if you compare  
11 with the alternative is, which is basically new peaking, it  
12 is actually much more efficient to use the new peakers with  
13 their, you know, 9,000 heat rates quick starting capability,  
14 no need to keep them on. It is much more efficient from an  
15 environmental and energy perspective to use those plants.

16 MR. MICSA: It they would be permitted for just  
17 close to about the same amount of hours and we would not  
18 have an inertia problem, I would totally agree with you.

19 MR. TURNER: Right, thank you.

20 COMMISSIONER BYRON: Right. Inertia, grid  
21 stability, and ramping, there are a lot of factors at play  
22 here. Sir, thank you very much. I think we will go ahead  
23 and press on. I think we are doing pretty good on schedule,  
24 Ms. Korosec, are we?

25 MS. KOROSEC: I believe so. We have one more

1 presentation before lunch from LADWP.

2 COMMISSIONER BYRON: Good. I show that we have  
3 Mr. Kenneth Silver from Los Angeles Department of Water and  
4 Power. Mr. Silver, we have not met, however, I heard about  
5 you. I am very glad that you are here today. We know that  
6 Los Angeles Department of Water and Power has a number of  
7 plants in this area, and are very concerned about the same  
8 issues that we have been discussing with Southern California  
9 Edison and the ISO. We welcome your input and thank you for  
10 being here today.

11 MR. SILVER: Well, thank you. I am glad to be  
12 here. I am the Manager of Energy Control and Extra High  
13 Voltage Stations. I am not a Transmission Planner, I am a  
14 Reliability type person. So I will be speaking from that  
15 frame of mind.

16 COMMISSIONER BYRON: In fact, if I could, this is  
17 one of the only presentations I do not have. Do we have  
18 copies of this, Ms. Korosec? Thank you. Please go ahead.

19 MR. SILVER: Yeah, we were not aware that -- we  
20 brought it up with us today, we were not aware that they  
21 were to be hand-outs. I apologize for that.

22 COMMISSIONER BYRON: That is all right.

23 MR. SILVER: Briefly, I am going to talk about --  
24 give you an overview of the Department system. You are  
25 probably aware of reliability criteria, but I just want to

1 touch on how we use reliability criteria, determine our  
2 requirements, a brief evolution of the LADWP transmission  
3 system, why local area generation is needed, our present and  
4 future requirements in jittery general terms, and  
5 opportunities for transmission upgrades.

6 LA is a vertically integrated utility, so we do  
7 have the benefit of owning most of the transmission and  
8 generation that we use. We have a mix of generation in the  
9 Los Angeles Area which is primarily gas-fired and hydro-  
10 electric. Externally, we import a wide variety of  
11 resources, coal, nuclear, hydro generation, we also take  
12 advantage of our transmission system to bring in energy from  
13 the Pacific Northwest and elsewhere on the WECC system.  
14 Generally, large scale renewable energy will be coming in  
15 from outside the Los Angeles Area, and when I say Los  
16 Angeles Area, I am talking about the City of Los Angeles,  
17 not as the ISO refers to the LA Area. And this will have to  
18 be brought in our import transmission system.

19 And the genesis of our system is that the  
20 generation was strategically located for reliability. Our  
21 transmission internal to our system is a network of 138 and  
22 two 30 kV lines and cables, and then we have an external  
23 network of 287 kV, 500 kV, and high voltage DC that we use  
24 for importing power to the system. In our transmission  
25 system, as you will see a little later, is somewhat of a



1 belt loop that we use for moving power around the city.

2           In reliability criteria, LA, like all of the  
3 utilities, are required to meet the reliability standards  
4 set forth by NERC and enforceable by FERC. The transmission  
5 reliability criteria that we basically follow is that  
6 sufficient generation be online or immediately available to  
7 meet some criteria. The first is sufficient appropriately  
8 located generation must be online, and producing energy so  
9 that pre-contingency, meaning normal operation, all of our  
10 circuits are loaded within their continuous capability, and  
11 all of our voltages are normal, and that following a  
12 contingency, which can be a loss of a generator or a line,  
13 that no circuit would be loaded beyond its emergency rating  
14 and that voltage settles out of at least 95 percent.

15 Secondly, we have to have sufficient appropriately located  
16 generating capacity that is either online or available in a  
17 short period of time, such that we can offload circuits that  
18 might be overloaded following a contingency back to their  
19 continuous rating, and also returning the voltage to normal.

20           The evolution of the DWP system -- in the 1940s  
21 through 1960, Los Angeles was experiencing rapid load growth  
22 and local area gas-fired -- or, at the time, gas and oil-  
23 fired generation -- was constructed mostly along the coast.  
24 And the LADWP transmission system was constructed to  
25 transmit that power from those primarily coastal power

1 plants to the growing load centers inside Los Angeles.  
2 Then, starting in the 1960s and presently, we began  
3 participating in jointly operated power plants that were  
4 remote from the City of Los Angeles, and also accessing the  
5 low cost energy which was available from the Pacific  
6 Northwest. We built a large high capacity transmission  
7 network to bring this energy into the City of Los Angeles,  
8 however, most of those tie lines tie into the northern part  
9 of our system. This under -- as the load goes up, this can  
10 create a very high north to south flow on our in-City  
11 transmission system, above what it is capable of carrying,  
12 and that is why we are required to run the coastal  
13 generation to offload those circuits, and basically supply  
14 the local area demand in that part of the city. This  
15 reliability generation is required year-round, but obviously  
16 the requirement increases as our load increases.

17           A quick diagram. In 1949, you can see the genesis  
18 of our system. At the very bottom, you can see our Harbor  
19 Generating Station, our first coastal plant, feeding our  
20 system. And then, in 1959, our system was rapidly  
21 developing, we were adding additional generation, adding  
22 additional receiving stations, which are high voltage  
23 substations throughout the city, we brought in some power  
24 from the Owens Valley, and added the Valley in Scattergood  
25 gas-fired plants.

1           COMMISSIONER BYRON: That is the SCA over on the  
2 left-hand side?

3           MR. SILVER: That would be Scattergood.

4           COMMISSIONER BYRON: Thank you.

5           MR. SILVER: And at this -- this is the point  
6 where this pattern began the form of importing in the north  
7 and generating in the south. By 1975, our system was at a  
8 point where it generally exists today, we have made some  
9 additions, some upgrades, some modifications, but really the  
10 basis of our system's existence since 1975. We added,  
11 again, some additional stations. We began importing coal-  
12 fired generation. The operation of the Pacific DC Inter-  
13 tie, and added our Castaic Pump Storage facility, and at  
14 that time, the Haynes Generating Station was also built.  
15 Again, importing from the north and generating in the south.

16           This is our 2009 system, and the big addition is  
17 all external to the system, so we are bringing in -- as our  
18 load has gone up, we are bringing in -- more and more energy  
19 is being imported. But, again, the transmission is not  
20 capable of moving that all the way from the north part of  
21 our system to the southern part of our system.

22           COMMISSIONER BYRON: Mr. Silver, before you leave  
23 that screen, there are 60 years of transmission and  
24 generation just re-condensed into one slide in two minutes.  
25 A couple of basic questions. Is your system completely

1 independent? Can it operate independently of the  
2 surrounding grid?

3 MR. SILVER: To the standpoint of serving our  
4 load, not talking about the resource that serves it, but  
5 serving our load, our in-city transmission system serves our  
6 load, we are not dependent on any of that. But our external  
7 transmission system is closely linked and intertwined and  
8 overlaid with the California ISO transmission and other  
9 utilities' transmission. So from that standpoint, we cannot  
10 pull that out and separate ourselves from other utilities.  
11 Most of those large resources -- all those large resources  
12 that we are partners in are owned by other -- jointly owned  
13 with other utilities, so we cannot just segregate our share  
14 out.

15 COMMISSIONER BYRON: Thank you.

16 MR. SILVER: Okay. In 2009, we are importing from  
17 our Intermountain Generating Station in Utah, Palo-Verde,  
18 and we are also beginning to import renewables into the  
19 system. As I mentioned earlier, most large scale renewable  
20 projects are going to be located outside of the City of Los  
21 Angeles, so while they may fit into the Los Angeles area  
22 from a broader term, from our imports, they may look like an  
23 import just like something from the Northwest or Arizona to  
24 our system.

25 The kind of hard to read colored diagram is the

1 City of Los Angeles, and unfortunately it is a little hard  
2 to see on the screen, but there is a belt loop system, as I  
3 mentioned earlier, of the 150 and 230 kV circuits, and the  
4 power from the external system comes in from the north, you  
5 can see all that, all those lines there on the top of the  
6 picture, that is our import capability. And as I mentioned,  
7 the internal transmission system cannot transmit all the  
8 needed power to the central, western, and southern portions  
9 of our city, all of that import capability enters our city  
10 in the San Fernando Valley, which is the northern part of  
11 our system.

12           Why is local area generation needed for  
13 reliability? It provides dynamic voltage support. You can  
14 put in a lot of capacitors and things to support voltage,  
15 but for quick response and dynamic and transient stability,  
16 there is nothing better than a rotating generator to provide  
17 that dynamic voltage support. The local area generation  
18 provides energy needed to maintain the transmission within  
19 its pre and post contingency limits. It also -- everybody  
20 else -- we have talked about inertia. Now, I am not an  
21 engineer, but inertia as I understand it, it is that  
22 rotating mass when you have a sudden loss of generation, or  
23 an increase of load, or a fault on the system, the system is  
24 attempting to slow down and that rotating mass, that  
25 inertia, is what keeps the system going in that transient

1 period. Inertia is also needed to import into the general  
2 Southern California Area, that SCIT that was mentioned  
3 earlier. And also, we operate two high voltage DC systems.  
4 High voltage DC systems need a strong robust AC system to  
5 work, so if you shut down the generation, you lose what is  
6 known as short-circuit duty, it is that ability to -- I lost  
7 the words -- the HVDC system has to commutate, or move  
8 energy from one valve to the other, and it requires that  
9 strong AC system to do that. So if you shut down the local  
10 area generation, you reduce the ability to operate the DC,  
11 which is the main import path for us.

12 As far as present and future requirements, we will  
13 continue to need to have sufficient local area generation  
14 strategically located. As we look at the numbers of what we  
15 need, we have to take into account historical and  
16 anticipated forced outages and reductions. You know,  
17 generation, particularly thermal generation, does have an  
18 outage history, and generally not all of your generators are  
19 going to be available all the time.

20 COMMISSIONER BYRON: So would it be correct for me  
21 to assume "strategically located" means at the end of  
22 existing transmission lines?

23 MR. SILVER: Well, for the LA system, it is in  
24 that southern portion of our system, which is where our  
25 coastal plants are. So it is at the end of -- it is at the

1 southern end of our load center, basically.

2           Because of our requirements, the current  
3 generation cannot be retired until an equivalent resource is  
4 constructed in the same or a comparable geographic area.

5           This table shows our local capacity requirements  
6 for the summer of 2009. The first column assumes that all  
7 of our generating units in our system -- and when I say all  
8 the thermal units, the units that provide that reliability,  
9 are available, and it sets forth our optimal generation.  
10 The first column would be our optimal generation plan. But  
11 because of the fact that we know where there is often going  
12 to be units on outage, as you move across the table, it  
13 describes what the requirement would be for loss of various  
14 generators, for loss of the Haynes unit, loss of the  
15 Scattergood unit, the loss of a valley unit. To some  
16 extent, we can substitute generation from one plant to  
17 another, but often times it is less effective, so you would  
18 need more generation from the alternate area than you would  
19 from the primary area. And this dispatch is optimized  
20 because we have a variety of constraint paths in our  
21 transmission system. So this is optimized to have the least  
22 amount of generation to handle or offset all of those  
23 constrained paths. One important difference is that there  
24 is a difference between the capacity, or the amount of  
25 generation available, and the energy it is actually

1 producing. And, as I mentioned earlier when I was talking  
2 about the reliability criteria, we need to be producing a  
3 certain amount of energy at all times. To meet the pre-  
4 contingency requirements, we have to have enough capacity  
5 available so that we can load that capacity up to meet post-  
6 contingency requirements. So, as you can see, the top table  
7 is an energy requirement, and this would be for a peak load  
8 day in 2009. The top table is an energy requirement, the  
9 bottom table is a capacity requirement. The first column  
10 there, NOB, is an indicator that is used for the Pacific DC  
11 inter-tie, and that is in there to kind of represent the  
12 northern imports. And as you can see, with higher northern  
13 imports, we have higher reliability generation requirements  
14 because of that flow down through our system. So when you  
15 increase imports, you sometimes increase the reliability,  
16 you cannot trade off one for the other.

17 On a tabular format, our RMR requirement for 2009,  
18 you can see there is a Haynes requirement, a Scattergood  
19 requirement, a Harbor requirement, and a Valley requirement,  
20 and this would be the optimal spread. The table previously  
21 showed the Megawatt amounts, this is showing it somewhat  
22 geographically, the red triangles being the generating  
23 sources that can supply this reliability energy.

24 Also, in considering our present and future  
25 requirements, we also have to take into account the



1 transmission forced outages. Our transmission is  
2 susceptible to failure, as anybody's is. We are vulnerable  
3 to seasonal fires, we have had major transmission  
4 disturbances twice in the last year due to fires in Northern  
5 Los Angeles County. We also have to have sufficient local  
6 area generation available to compensate for the forced  
7 outage of other generation that might be lost. And we have  
8 to have sufficient dispatchable generation to regulate and  
9 back-up intermittent resources such as wind and solar.

10 Our planned repowering projects may change the  
11 operation of these coastal generation, but will not have a  
12 significant impact on the capacity requirements and the  
13 energy requirements during the peak times of the day. Now,  
14 what that says is that there are some generators, but they  
15 are not cycleable; because we need them during the day, they  
16 operate at night because we cannot take them off at night.  
17 Under different repowering scenarios, there may be an  
18 opportunity to run less generation at night, but repowering  
19 is not going to reduce the day-time requirement.

20 COMMISSIONER BYRON: And just so I understand, it  
21 is the design of those old power boilers that do not enable  
22 you to cycle them night time/day time. Is that correct?

23 MR. SILVER: That is correct.

24 COMMISSIONER BYRON: And that is not changeable?

25 MR. SILVER: Yeah, that is not changeable. And

1 even some large combined cycles, if you need the units for  
2 18 hours a day, it may not be productive to shut them off  
3 because they may only be off for two or three hours before  
4 you have to begin your restart cycle.

5 COMMISSIONER BYRON: And is that also because you  
6 are decreasing the life of the plant when you do that kind  
7 of cycling?

8 MR. SILVER: Cycling does increase maintenance  
9 costs. If you do enough maintenance, it may not necessarily  
10 reduce the life of the plant, but it is going to require a  
11 lot more maintenance. And more frequently and more  
12 expensive maintenance to maintain the units. Renewables can  
13 meet general energy needs, but they do not meet the  
14 reliability capacity to require regulation and also the  
15 locational needs as I have described.

16 Opportunities for transmission upgrades. The  
17 local area transmission, again, I said was initially  
18 constructed to move power from south to north in those early  
19 years. The early transmission was comprised of 138 kV  
20 circuit lines and cables, with later additions being at a  
21 higher capacity 230 kV. There is a limited ability to  
22 upgrade the internal transmission primarily due to the fact  
23 that Los Angeles is a dense metropolitan area. The  
24 available rights of way are pretty much used up, so there is  
25 not a lot of opportunity to add additional lines, and only

1 minimal opportunity to upgrade what is already there, to put  
2 something in higher voltage.

3 COMMISSIONER BYRON: And I suspect you have looked  
4 at those options, when you say there is minimal opportunity  
5 to go to a higher voltage, because most of those upgrades  
6 have already taken place?

7 MR. SILVER: They have been looked at, they have  
8 not necessarily taken place because they did not -- they  
9 would not have had much impact on the requirements, so it  
10 would have been money spent for very little benefit.

11 COMMISSIONER BYRON: Thank you.

12 MR. SILVER: We do have a 10-year transmission  
13 plan. If the plants are primarily focused on load growth  
14 and renewable integration, again, we have looked at  
15 opportunities to upgrade in the city transmission;  
16 unfortunately, I do not have readily our most recent plan, I  
17 was not able to see that, to see how recently we studied the  
18 ability to upgrade transmission and reduce that coastal  
19 generation, but previous plants show that there was not a  
20 lot of bang for the buck, basically.

21 We looked at plants to upgrade the old 138 kV  
22 system, and that was found to be impractical due to the  
23 infrastructure constraints. Some of the 138 kV stations are  
24 in constrained areas, surrounded by business or residential,  
25 and there is not an opportunity to make the station bigger

1 to accommodate more transmission or higher voltage  
2 transmission.

3 COMMISSIONER BYRON: When you say "station," do  
4 you mean substations?

5 MR. SILVER: Substations.

6 COMMISSIONER BYRON: Yeah, because it is a  
7 clearance issue, right?

8 MR. SILVER: Right.

9 COMMISSIONER BYRON: And not only do you need to  
10 change out every single piece of equipment and re-conductor  
11 -- well, you would not necessarily need a re-conductor, but  
12 the substations need to be bigger.

13 MR. SILVER: You need more space; that is correct.  
14 Rights of way for overhead transmission are not available.  
15 Underground, it is very difficult and costly to install, but  
16 in the middle of Los Angeles, it is hard to dig up a street  
17 and put in an underground cable on a multi-month, multi-year  
18 project. And cables inherently have a much lower capacity  
19 than an overhead line does, so putting in a lot of cables is  
20 somewhat problematic.

21 Bruce Moore, from our Environmental Group, is  
22 going to touch on some final aspects, and I will be  
23 available to answer questions.

24 COMMISSIONER BYRON: Thank you. Welcome, Mr.  
25 Moore.

1           MR. MOORE: Thank you. Good morning. I will be  
2 discussing the Department's Planned and repowering projects  
3 and the ERC requirements for those projects.

4           The Haynes Generating Station in Long Beach will  
5 replace two steam boiler units with advanced simple cycle  
6 gas turbines. This will result in a reduction in air  
7 pollution on a pounds per Megawatt hour basis. The 616  
8 Megawatts of gas turbines will increase the capacity of the  
9 facility by 12 Megawatts, gross Megawatts, with no increase  
10 in the net capacity. The DWP has already acquired  
11 sufficient PM and POC ERC's Emission Reduction Credits from  
12 the market to cover the emissions associated with this 12  
13 Megawatt capacity increase. The DWP has applied to the  
14 SCAQMD for the Rule 1304 exemption from the ERC requirement  
15 offered by the AQMD's rules. The Rule 1304 exemption is an  
16 exemption from the offset and modeling requirement for  
17 repowering projects that use advanced gas turbines up to the  
18 capacity of the units being replaced. In the absence of  
19 Rule 1304, DWP would need to acquire over 900 pounds per day  
20 of PM ERCs for the Haynes project, and this amount of ERCs  
21 is not available on the market at this time.

22           The DWP is in the preliminary stages of designing  
23 a Scattergood repowering project which will replace two  
24 steam boilers with gas turbine technology, probably a  
25 combination of simple cycle and combined cycle.

1           The SCAQMD has held a number of workshops  
2 regarding the streamlining of its new source review  
3 regulations. One proposal is to calculate the ERC  
4 requirement on an annual, rather than a monthly basis. The  
5 daily ERC requirement for a project is currently calculate  
6 by calculating the emissions during the highest operating  
7 month and dividing by 30. One proposal made at the  
8 workshops is to perform the ERC calculation on an annual  
9 basis, rather than a monthly one. This change to the  
10 calculation method would significantly reduce the ERC  
11 requirement for many projects, particularly seasonal  
12 industries like electric utilities where the difference  
13 between the load in the summer and the winter is very  
14 different. That concludes my comments and Ken Silver and I  
15 are available for questions.

16           COMMISSIONER BYRON: Mr. Moore, a quick question  
17 if I may. Given that exemption that you mentioned that is  
18 available to you under Rule 1304, could you describe that in  
19 a little bit more detail? Is that unique for LADWP versus  
20 the other generating stations in the area?

21           MR. MOORE: It is a general AQMD exemption from  
22 the modeling and offset requirements for when a steam boiler  
23 is being replaced by advanced gas turbines or other advanced  
24 technology.

25           COMMISSIONER BYRON: So does that apply to any

1 repowering?

2 MR. MOORE: It applies to any repowering.

3 COMMISSIONER BYRON: So here you have outlined a  
4 plan, or what your plans are in one slide. Does this mean  
5 LADWP is in the clear with regard to once-through cooling  
6 and priority reserve? All it takes is money to do the  
7 repowering and you are done?

8 MR. MOORE: It appears that the LADWP is in the  
9 clear with regard to the PM ERC problem, particularly now  
10 that the Judge in the LA Superior Court lawsuit has narrowed  
11 the rip and allowed the 1304 exemption to be used once  
12 again. I was not fully briefed on the once-through cooling  
13 issue before coming to this meeting, so I am not qualified  
14 to speak to that.

15 COMMISSIONER BYRON: Yeah, I am sure that there  
16 will be more -- you are probably not in the clear on that  
17 one. Commissioner, do you have any questions?

18 VICE CHAIR BOYD: Hopefully a simple question. I  
19 was just curious why the Haynes repower would go with simple  
20 cycle, even though I see there advance simple cycle versus  
21 your comment that the other plant might go through a  
22 combination combined cycle and simple cycle.

23 MR. MOORE: I am not sure I am the right person to  
24 address that, but I can say that the Haynes project is  
25 designed to be a quick start project, so that when the sun

1 is not shining --

2 VICE CHAIR BOYD: Base load --

3 MR. MOORE: Right, when the sun is not shining, or  
4 the wind is not blowing, and we need to pick up load  
5 quickly, we will have those six gas turbines there ready for  
6 a quick start.

7 MR. SILVER: This Haynes repower is actually our  
8 second Haynes repower. We have previously done a repower  
9 with a combined cycle, so we have already made that first  
10 step.

11 VICE CHAIR BOYD: Yes, I painfully remember that.

12 COMMISSIONER BYRON: Yes, you are referring to  
13 when the projects come through the Commission, correct?

14 VICE CHAIR BOYD: Or do not come through -- in  
15 this case, do not come through.

16 COMMISSIONER BYRON: You know, Commissioner, I  
17 have received in the past a personal commitment from the  
18 General Manager of LADWP, David Nahai, that they are going  
19 to work cooperatively with the California Energy agencies on  
20 addressing the priority reserve and once-through cooling  
21 issues, and I know that he has also expressed to me the  
22 concern about the external efforts, shall we say, to exert  
23 control on local decision making capability. In general, I  
24 find a lot of folks that come to Sacramento do not  
25 necessarily like being here. But also, the grid is



1 connected and we certainly understand that the once-through  
2 cooling issue and this issue affect you in the same way it  
3 affects the plants that operate in the ISO served control  
4 territory. So I guess I also want to add, we have also seen  
5 tremendous strides that LADWP has been making, not just  
6 verbal commitments in terms of moving towards renewables,  
7 and trying to address some of the larger policy issues that  
8 are being imposed on everyone here from Sacramento. It is  
9 extremely important that we have Los Angeles Department of  
10 Water and Power at the table. We need your input and  
11 information. I would like to thank both of you for being  
12 here today and being as forthcoming as you were, with  
13 information that is very helpful. We need to work closely  
14 with you to help solve these problems going forward. So I  
15 appreciate your being here. I do not have any additional  
16 questions for you, but -- oh, Ms. Korosec says --

17 MS. KOROSEC: We do have one question on the  
18 WebEx, Mr. Rising.

19 MR. RISING: I have a request of the previous  
20 speaker. Have you got a figure or an estimate in mind as to  
21 how many Megawatts of dispatchable generation would be  
22 needed for how many Megawatts of renewables that are being  
23 considered in the RPS?

24 MR. SILVER: Unfortunately, I do not have an  
25 answer for that question. That is certainly a study that we

1 are undergoing now as we are integrating in the near future  
2 a large amount of intermittent generation, but I do not have  
3 a number at this time.

4 MR. RISING: Okay.

5 MS. KOROSK: And I believe we also have another  
6 question in the room.

7 MR. NAZEMI: Good morning. I am Mohsen Nazemi. I  
8 am Deputy Executive Officer with South Coast Air Quality  
9 Management District. I will be speaking after lunch  
10 regarding the PM-10 offset issues and South Coast. I will be  
11 addressing some of the issues that were discussed with the  
12 previous speakers, but specific to the question Commissioner  
13 Byron, you asked from Mr. Silver, I would like our Principal  
14 District Counsel to clarify the response that you received,  
15 which we do not believe is correct, so if you would allow me  
16 to have Ms. Barbara Baird give an answer from our  
17 perspective, I would appreciate that.

18 COMMISSIONER BYRON: Certainly.

19 MS. BAIRD: Good morning, Commissioners. My name  
20 is Barbara Baird, District Counsel for the South Coast Air  
21 Quality Management District, and I appreciate your granting  
22 me the opportunity to talk here. This is specific to the  
23 question whether LADWP is in the clear because of the  
24 ability to use the Rule 1304 exemption, plus they have  
25 credits for those emissions that are not covered by the

1 assumption. The difficulty is that the Court Order that Mr.  
2 Moore mentioned specifically says the District may not use  
3 Rule 1315, which is our credit generating rule, in order to  
4 use the 1304 exemption. So unless legislation that has been  
5 passed by the Legislature, but not yet signed, goes into  
6 effect, we are still in a situation where we have no credits  
7 to give, even though the injunction does not prevent us from  
8 giving them. So we do not think they are in the clear at  
9 all.

10 COMMISSIONER BYRON: So which legislation? AB  
11 1318 or SB 827?

12 MS. BAIRD: In his case, it would be SB 827  
13 because he is relying on a 1304 exemption, which is covered  
14 under 827. Thank you for the opportunity.

15 COMMISSIONER BYRON: Absolutely. Was that  
16 helpful?

17 MR. MOORE: That was very helpful. Thank you,  
18 Barbara.

19 COMMISSIONER BYRON: How many attorneys are in the  
20 room?

21 VICE CHAIR BOYD: There is another one.

22 COMMISSIONER BYRON: All right, please.

23 MS. LAZAROW: Good afternoon. My name is Shana  
24 Lazarow. I am an attorney with Communities for a Better  
25 Environment, and I actually want to clarify what Ms. Baird

1 just tried to clarify, if I may.

2 COMMISSIONER BYRON: I remind everyone, this is  
3 not a court of law.

4 MS. LAZAROW: Of course, I just wanted to point  
5 out that the rule to which Ms. Baird referred, Rule 1315,  
6 has never been used by the District. So for years these  
7 1304 exemptions have been issued for repowers and they  
8 should continue to be -- it should be continued to be used  
9 for repowers like the ones proposed by LADWP. The fact that  
10 1315 was never legally adopted should have no impact on the  
11 implementation of that properly adopted rule. Thank you.

12 COMMISSIONER BYRON: I am glad Commissioner Boyd  
13 understands all this.

14 VICE CHAIR BOYD: I have already described this as  
15 a chess game.

16 COMMISSIONER BYRON: Was that helpful?

17 MR. MOORE: It was truly helpful.

18 COMMISSIONER BYRON: Are there any other questions  
19 or clarifications before we break for lunch? Gentlemen, I  
20 hope you will be with us for the rest of the day. Thank you  
21 again for being here. Ms. Korosec, may we break?

22 MS. KOROSEC: Yes, let's break and return at 1:15.

23 COMMISSIONER BYRON: 1:15. Thank you all very  
24 much.

25 [Off the record at 12:17 p.m.]

1 [Back on the record at 1:19 p.m.]

2 COMMISSIONER BYRON: Ms. Korosec, let's go ahead  
3 and start. I think Commissioner Boyd will join -- rejoin us  
4 soon. But I think we should go ahead and get started  
5 because we still have a lot of material.

6 MS. KOROSEC: That is true, we have got a lot to  
7 cover this afternoon. So we will be starting up with a  
8 presentation from Richard McCann from Aspen Environmental  
9 Group.

10 MR. McCANN: Good afternoon. I am Richard McCann.  
11 I am an Economist with Aspen Environmental Group. And I  
12 want to open with -- I like economists jokes and I keep a  
13 list of them, and one of my favorite jokes is about three  
14 individuals trapped on a desert island, they have been  
15 eating coconuts the whole time, and a can of beans washes up  
16 on the ocean, on the beach. It is an engineer, biologist,  
17 and an economist. And so they are trying to figure out how  
18 to get this can of beans open and the biologist says, "Well,  
19 we've got coconuts, we can smash this can open," the  
20 engineer says, "No, that's going to destroy the beans," so  
21 he says, "I can put this out in the sun, get up to super  
22 critical heat and it will explode," and the economist says,  
23 "Why are you guys making this so complicated? Let's just  
24 assume a can opener." I tell this joke because, to a  
25 certain extent, what we are doing here with this analysis is

1 try to show where the can openers are being assumed by the  
2 various folks looking at this problem. And so we are going  
3 to walk through an analysis that shows different capacity  
4 requirements and some of the other constraints in looking at  
5 this, and try to shed a little bit more light on some of the  
6 constraints that are apparent in trying to address this  
7 problem.

8           So I am going to walk through first an overview of  
9 the problems and issues. I am going to go through this  
10 pretty quickly because I think everybody in the room seems  
11 to understand this better than I do in some of these areas.  
12 Now I am going to talk about the analytical approach and  
13 caveats to our analysis, and then Cory Welch, who is with  
14 Summit Blue, is going to walk through the scenarios and  
15 results. They conducted the in-depth, detailed analysis  
16 with working with David Vidaver from the Commission staff,  
17 and then we are going to talk a little bit about conclusions  
18 and further analysis, including some additional data and  
19 information that would be helpful in this process.

20           COMMISSIONER BYRON: And I just want to confirm,  
21 how much time do we have allocated for your presentation?

22           MR. McCANN: Forty-five minutes. We should be  
23 able to do that quite easily.

24           COMMISSIONER BYRON: All right, thank you.

25           MR. McCANN: Of course, the overview of the

1 problem in this has been addressed several times, and I am  
2 going to just go through this quickly, one is addressing the  
3 issue of peak load reliability, both within SB 26 and within  
4 DWP, dealing with transmission and resource constraint  
5 conditions. The second is the push for retiring or  
6 replacing OTC units, and the third is being able to acquire  
7 enough ERCs in order to replace generation as needed, over  
8 the next period until about 2020.

9           The important environmental constraints that we  
10 are facing are the proposed orders by the State Water Board,  
11 the ERC issue in the South Coast, and then what we are  
12 looking at is the interaction between these two policy  
13 objectives, and then also meeting reliability in RPS goals  
14 at the statewide level. What we were doing was, first off,  
15 trying to create a tool to estimate the resource  
16 requirements for peak loads during the period out to 2018,  
17 the minimum operating requirements for replacing OTC  
18 capacity, and I am going to talk about some of the caveats  
19 of that in a moment, and then also looking at the ERCs that  
20 were created and also needed in order to replace the OTC  
21 units. I also want to say something about this tool, is  
22 that it is really a reduced form tool, that is that we took  
23 public data, and took some results from some of the analytic  
24 models out there, the very complex models, and essentially  
25 derived the important parameters from those models so that

1 we could put them into a simpler spreadsheet type model. We  
2 started with an Excel model and then moved on to analytic,  
3 which uses the same kind of platform, and Cory can explain a  
4 little bit more about that model. And then we were able to  
5 run a number of different scenarios very -- quite quickly,  
6 and we were able to do this with this tool, we were able to  
7 look at scenarios quite often, and so that this is a very  
8 useful way of looking at this policy problem, is to be able  
9 to do this type of reduced form analysis using, in some  
10 cases, heuristics, in contrast, running very complex  
11 transmission planning models, which are useful for when you  
12 are doing your final design on your transmission system, but  
13 may not be really the appropriate tool for doing this type  
14 of policy analysis.

15           What we did is we looked at a number of scenarios  
16 that varied by different types of demand forecasts, and  
17 different types of retirement scenarios, and resource  
18 additions. What we were looking at is, if you stress the  
19 system in certain ways, how the environmental constraints  
20 impinge on meeting your reliability goals that you have for  
21 your system.

22           This is just an overview of the model that we  
23 have. This is -- on the right-hand side is the input and  
24 output sheet for the analytical model that we have. This is  
25 an exploratory model, it is not a truly predictive answer of



1 what will happen. What we are looking at is what might  
2 happen under different types of demand and resource  
3 scenarios. It is flexible, it is focused on scenario  
4 analysis, it is a very transparent model, you can look at  
5 the assumptions very quickly by pushing the different  
6 colored buttons that are on the screen, it is easy to  
7 inspect and modify the inputs, and you vary the assumptions  
8 in a multitude of dimensions with this particular modeling  
9 platform.

10           One of the things that we started with was a  
11 topology of the transmission system for both the ISO and  
12 DWP, and you can see the overlap and interconnections  
13 between the different systems, and this was in some ways the  
14 framework in which we were starting from in order to try to  
15 identify the various constraints that the system faces. One  
16 of the key things that we had to do was derive what were the  
17 transmission congestion constraints on both the DWP and ISO  
18 systems, and you can see from these graphics, what we did  
19 was we started from 2007 load data in both cases, and in the  
20 case of DWP, we had actual load degeneration data from DWP  
21 and it is the light blue graphic -- the purple line that  
22 sort of squiggles around the right-hand side of that  
23 mountain is the transmission constraint for DWP, given an  
24 assumption that it imports all of its energy needs, but  
25 still needs to meet in-Basin reliability requirements. So

1 essentially what is happening is DWP's generation is only  
2 running to meet reliability, but not economic energy  
3 requirements. And so that was our upper bound on  
4 transmission capacity for imports during different hours of  
5 the year, under various load conditions. And then, on the  
6 right-hand side is the ISO version of that graphic, again,  
7 the pink line is the upper level of transmission capacity  
8 and the yellow line is the lower bound. In the case of the  
9 ISO model, what we did was we ran the FNM model under 2007  
10 conditions, and derived -- again, in reduced form -- the  
11 transmission capacity relative to load conditions, and  
12 generation conditions in which all generation was solely for  
13 reliability reasons, we assumed 100 percent imports to meet  
14 all economic energy requirements.

15 COMMISSIONER BYRON: And, excuse me, Mr. McMann --  
16 I am sorry, Mr. McCann -- what is the vertical access on the  
17 left figure? Does it say "observations?"

18 MR. McCANN: Observations, right. That is the  
19 number of hours that a particular load was observed, so the  
20 highest peak is around 3,500 Megawatts of load, you can look  
21 on the right-hand access, it says load Megawatts, and so the  
22 highest number of hours at which LADWP experienced a load  
23 was at 3,500 Megawatts, or, in other words, it runs most  
24 often at about 3,500 Megawatts. But the size of the load,  
25 that peak, is not really that important to our analysis, it

1 is a graphical way of showing how we ended up driving our  
2 results.

3 COMMISSIONER BYRON: But the observations we need  
4 to be concerned about are the few number that fall outside  
5 the bands that you have got?

6 MR. McCANN: Right. Or approximately so. What we  
7 were looking at, those are the peak import hours. And, in  
8 fact, we are being conservative by drawing that purple line  
9 inside the observations. They, in fact, have the capability  
10 of importing more Megawatts than what we have in that curve,  
11 but we were trying to be conservative in our estimate of  
12 what their import capacity was.

13 COMMISSIONER BYRON: Okay.

14 MR. McCANN: The computer is running a little  
15 slow. So what we are looking at are a couple of key  
16 relationships. The first one, we are trying to estimate the  
17 local capacity requirements, regardless of the resource  
18 conditions, which is we are estimating the peak resource  
19 requirement and looking at the maximum amount of imports via  
20 transmission, and then estimating what is the internal or  
21 in-Basin capacity requirement for both DWP and for the ISO,  
22 and we estimated those independently of each other. And  
23 then, a second relationship we are looking at is the  
24 additional capacity that is required to displace fossil  
25 fueled OTC units. We have the capability of looking at if

1 we are going to retire San Onofre, as well, but that is not  
2 a case we looked at as being immediately relevant to the  
3 analysis that we were doing. So what we are essentially  
4 doing is trying to estimate, if you had to build a certain  
5 amount of new capacity to retire different amounts of OTC-  
6 type units, how many Megawatts would you need, given these  
7 various capacity requirements in-Basin.

8           Also, we are looking at the amount of ERCs that  
9 were needed under the different scenarios, and we were  
10 looking at both the ERCs that are produced when you retire  
11 an OTC unit, and we estimated those from historic data, from  
12 ARB's Emission Inventory dataset. Those ERCs probably would  
13 differ year by year because these generating units -- it is  
14 based on the amount of generation that they actually produce  
15 throughout the year, but we only had historic data to work  
16 with, we did not have scenarios of future generations that  
17 we were working with. And then we also estimated the amount  
18 of ERCs needed to permit a new generating unit, and in most  
19 cases we took those ERC amounts from requests that were in  
20 the Applications for Certification and other siting  
21 information, much of it filed here at the Commission in the  
22 siting cases.

23           And then we were looking at -- we did not really  
24 look at the question of how new transmission and other  
25 generation factors would affect ERC production, or demand

1 for ERCs. In other words, we were not really looking at how  
2 the amount of generation would vary for new generation --  
3 the amount of emissions would vary with the amount of  
4 generation from new generating units, we just took the  
5 amount that was specified as a fixed amount in the  
6 applications, and that would be another step of the  
7 analysis. For example, a power plant might be estimating  
8 that they are running at a 20 percent capacity factor  
9 because they have a large amount of economic generation  
10 sales that they expect to have during the year, and so they  
11 might make an ERC application based on a 20 percent capacity  
12 factor. Well, it might turn out that you really only need  
13 that unit to run at a 5 percent capacity factor to meet your  
14 reliability requirements, we have not done the calculation  
15 yet for what that -- the amount of ERCs will be required for  
16 that level of generation, but that is something we could  
17 look at down the road.

18 COMMISSIONER BYRON: I just want to make sure I  
19 understand this, Mr. McCann, so when an Applicant comes  
20 before this Commission, and need to get ERCs for what they  
21 have applied for, whether they have run up to that level or  
22 not, so I am thinking that you are probably running a case  
23 that, even though it may not be real, it may not need all  
24 those ERCs, they have to acquire all those ERCs. So I think  
25 you are running the right case.

1           MR. McCANN: Well, I guess the question is, it  
2 would be a question of whether they have to acquire those  
3 ERCs. That is what they project that they need probably in  
4 order to make the economics of their power plant pass  
5 muster, but that may not be the amount of ERCs that you  
6 really need to have that power plant meet the reliability  
7 requirements that you need in-Basin. Do you understand the  
8 distinction between those two?

9           COMMISSIONER BYRON: Yes --

10          MR. McCANN: And so one is a wish list of ERCs and  
11 the other is the list of what you really might need for  
12 ERCs. Now, there are some contractual issues that might be  
13 related to that, that I can talk about.

14          COMMISSIONER BYRON: All right, but it is more  
15 than a wish list, they are not going to get a permit to  
16 operate unless they acquire all those ERCs.

17          MR. McCANN: Well, they have -- in their  
18 projections, they have a certain number of hours that they  
19 are projecting to run, but they actually create that  
20 estimate of how many hours they project to run. They are  
21 not told by someone that is how many hours they have to run,  
22 they have to do their own internal analyses and say, "Oh,  
23 well, we think we'll run at about a 20 percent capacity  
24 factor because that is what we need in order to make our  
25 financing work."

1           COMMISSIONER BYRON: Or, in order to fulfill the  
2 obligations of the PPA.

3           MR. McCANN: Right. And so that is where the  
4 contractual issue comes in to play is the PPA can be  
5 modified to meet a different need than what might be in the  
6 PPA.

7           COMMISSIONER BYRON: Okay, but I will just try  
8 this one more time -- it does not matter what the reason is,  
9 they are not going to get a permit to operate unless they  
10 acquire all the ERCs they request.

11          MR. McCANN: Right, yes. That is the first part,  
12 I am just saying that they could go back and modify the PPA,  
13 and reduce the amount of ERC requirements.

14          VICE CHAIR BOYD: One point being that,  
15 traditionally, people ask to absolutely maximize the hours  
16 they might run, therefore they are obligated to get ERCs to  
17 cover that. And I think Mr. McCann is pointing out that,  
18 quite possibly, they do not have to ask for that many --

19          MR. McCANN: Exactly.

20          VICE CHAIR BOYD: -- and thus the Air District  
21 requirement would be reduced, etc. etc. Interesting  
22 observation.

23          MR. McCANN: So, with this model, as I mentioned,  
24 it is a reduced form model and there are some other  
25 simplifying assumptions that we have made in this model.

1 There are certain things we can add to this model as it goes  
2 along in order to do more detailed analysis, but the first  
3 thing is that it does rely on a reduced form and some  
4 heuristics, and reveal characteristics in which we have  
5 looked at model results and historic system data, and we  
6 started this from using 2007 because that was the most  
7 complete year that we have of data. It focuses solely on  
8 meeting reserve margin targets as defined in the ISO's local  
9 capacity requirement analysis, and we tried to use similar  
10 parallel assumptions for DWP. It does not include economics  
11 or ancillary services, generation beyond the reliability  
12 requirements. And it also does not include some of the -- I  
13 will talk about some of these in caveats in some other  
14 dimensions that have already been talked about today -- it  
15 relies on published resource plans, to a large extent there  
16 is some confidential data that is included in the model, but  
17 it definitely does not necessarily represent the optimal or  
18 otherwise desirable plan. It is a set of plans that  
19 basically have been published in public places, and we do  
20 not check the economics or any other type of assumptions  
21 that are in the model to see if they are optimal.

22           The caveats as I mentioned in using this analysis,  
23 it does not include the ancillary services requirements that  
24 include sub-area minimum generation, voltage and stability  
25 support, the inertial constraints, the ramp rate limits, and



1 some of the other factors that have been described here.  
2 The transmission capacity is dynamically linked to load, but  
3 it is not linked to other variables such as the differences  
4 in generation levels. It is contingent on transmission and  
5 other resource plans, developing as specified by the ISO and  
6 DWP, along with some modifications made by the CEC staff  
7 input, but it does have those sorts of limits. The model  
8 does have the ability to use different resource plans if  
9 people want to come forward with different proposals. And  
10 then, in using the results, it is important to understand  
11 that these results are directional and indicative, not exact  
12 specifications of what may happen. But it is useful for  
13 assessing the feasibility of meeting different policy goals  
14 and the tradeoffs that the different agencies face in trying  
15 to make different resource planning decisions. While it  
16 shows the range of potential outcomes, you cannot really bet  
17 on the best outcome, you cannot plan on winning the lottery,  
18 you have got to look at the full range of scenarios and  
19 potential outcomes. And there are, in some cases, it will  
20 require more detailed modeling in order to address some of  
21 the caveats that I have discussed.

22           And then I am going to turn it over to Cory at  
23 this point and he is going to talk about different scenarios  
24 that we used, and then discuss some of the results, and then  
25 I will come back and talk about some of the conclusions and

1 additional data needs.

2 MR. WELCH: Thank you, Richard. As Richard  
3 mentioned, this tool is very focused on scenario analysis,  
4 it lets us look at a number of different situations and  
5 assumptions to understand the impacts that those assumptions  
6 have on reliability constraints, ERC needs, OTC capacity,  
7 and whether or not we can displace that, and so forth. So  
8 we actually analyze about 16 different scenarios with this  
9 tool. I am going to show eight of them here, just to keep  
10 it somewhat cognitively feasible, so we can absorb it into  
11 the amount of time that we have.

12 We looked at two different demand scenarios, a  
13 high stress and a low stress case, and I will define on the  
14 next slide what those scenarios really are. Likewise, too,  
15 transmission scenarios, one where we completely excluded new  
16 transmission so that we can see the impact of that, and one  
17 where we assume that the transmission plans go according to  
18 schedule. And then we looked at four different supply  
19 scenarios, and I will get into exactly what those supply  
20 scenarios are in upcoming slides, although I am only going  
21 to show you two of them, but they are the more extreme  
22 bounds of the scenarios we analyzed, so the intermediate  
23 ones, we do not lose a whole lot of information by excluding  
24 those from this analysis, or, excuse me, from this  
25 presentation.

1           The first thing that I have to apologize for and  
2 point out is that this slide on the screen is correct and I  
3 think what you have is a print-out, there are some things in  
4 reverse, so let me just point out what those are. The  
5 bottom line is a low stress case, it uses a high assumption  
6 about renewable penetration, so, obviously, if I have high  
7 renewable penetration, that reduces the need for capacity,  
8 and likewise, if I have a high utility scale, it reduces the  
9 need for new capacity to replace our fossil fuel OTC. So  
10 these are actually reversed in the paper you have, but they  
11 are correct on the screen. The low stress case uses a 2009  
12 draft mid-range forecast, may I emphasize the word "draft"  
13 there because my understanding is, just this last week,  
14 there is another workshop to update and finalize that, we  
15 had not incorporated that yet into our analysis. But, in  
16 general, that is a lower forecast demand than in the high  
17 stress scenario, which uses the 2007 IEPR forecast. And,  
18 again, my understanding is that the updated 2009 Forecast  
19 Demand is going to be somewhere in between those two, so,  
20 again, we sort of feel like we have bounded the problem  
21 here.

22           The transmission scenarios, again, I just have  
23 two. These are included or excluded. If it is excluded,  
24 that is zero; if it is included, new transmission comes  
25 online with the capacities that you see on this chart. So,

1 in other words, in 2013 and in the LADWP control area, I  
2 see, you know, roughly a 2,200 -- I think it is 2,266 or  
3 something to that effect, coming online in 2013, and about  
4 3,200 Megawatts of capacity in the CAISO controlled area by  
5 2013. And, again, we have the ability, the flexibility to  
6 adjust these numbers, to adjust the timing of this  
7 transmission coming online, and magnitudes, and so forth, so  
8 that we can understand the impact of that. On the supply  
9 scenarios, it is important to note that the supply scenarios  
10 incorporate two different things, 1) the retirement of  
11 existing OTC capacity, as well as new capacity that is  
12 postulated to come online. And in some cases, there is a  
13 net zero, in other cases there is a net increase or a net  
14 decrease, depending on the actual scenario that we are  
15 looking at, and I will walk through those again on the next  
16 slide.

17 I am going to show a low OTC retirement scenario  
18 and a long run OTC retirement scenario, and you will see how  
19 those are defined. I know this has been an I-chart, you  
20 have got it on your paper there, and so you can refer back  
21 to that as I go through the following slides and kind of  
22 see, well, what was coming online and when, because I know  
23 this is a big difficult to absorb. But from the CAISO  
24 perspective, you can pretty much think of the low OTC  
25 retirement scenario as not really changing much, nothing

1 really retiring, and I think only Riverside, in 96 Megawatts  
2 Riverside, coming online in January of 2011. In the long  
3 run OTC retirement scenario, we pretty much took the plans  
4 and the best estimates and some professional judgment with  
5 the assistance of the CEC staff, to come up with feasible  
6 retirement dates for these units. And in many cases, those  
7 are repowers, and in some cases those are re-powerings as in  
8 the case of El Segundo, in other cases they are new units,  
9 and in some cases we even kind of postulated our own  
10 additional capacity, which would be then replacing capacity  
11 that had retired.

12           For the LADWP analysis, we kind of originally came  
13 up with these scenarios, looking at both of them together,  
14 so unfortunately the low OTC retirement scenario and the  
15 long-run OTC retirement scenario do not differ a lot in the  
16 LADWP analysis; how they do differ is really in whether or  
17 not Scattergood Unit 3 is retired or repowered within the  
18 time frame of our analysis, which is 2009 to 2018. So in  
19 the low OTC retirement case, it is not retired, Scattergood  
20 Unit 3, and in the long run OTC retirement case, it is.  
21 These values, you may notice on the footnote in the previous  
22 slide, as Richard mentioned, these are based on publicly  
23 available documents. We looked at LADWP's capacity resource  
24 accounting tables, and basically plopped those dates into  
25 our analysis because that is the publicly available plan for

1 new capacity.

2           So the net impact of these additions to capacity  
3 and retirements is shown on these two slides. What you will  
4 see in the CAISO controlled area is that the low OTC  
5 retirement case, we see a fairly stable capacity line there,  
6 whereas, with the long run OTC retirement, you kind of see a  
7 peak coming on, and then in 2013, that is basically where  
8 that 850 Watt Sentinel peaker coming online, and then, as we  
9 retire additional OTC capacity and add less new capacity,  
10 this scenario showing a net decrease in your total capacity  
11 in the Basin. In the LADWP situation, really, the two  
12 scenarios, as I mentioned before, are very similar. You  
13 will see a slight divergence in 2018, and that is, again,  
14 really caused just by that Scattergood Unit 3.

15           COMMISSIONER BYRON: So are you looking up these  
16 two cases for LADWP's control area as bounding?

17           MR. WELCH: I would say in LADWP, I would not  
18 necessarily call those bounding. Again, when we sort of  
19 came up with these scenarios, we had a list of plants and  
20 said, okay, what do we think are likely scenarios? What do  
21 we think are likely situations? And I guess I would say  
22 that LADWP received a little less scrutiny in looking at the  
23 bounding scenarios as then did CAISO. But I think what we  
24 will see in the following slides is that we still have some  
25 information that I believe to be revealing about what is

1 going on in the LADWP area.

2           That said, if it is okay, Mr. Byron, I will jump  
3 to the next slide. This calculation, Richard showed this  
4 relationship, but let me just describe it again real quick  
5 here. It is the additional capacity that would be required  
6 to replace OTC. And when I say "additional capacity," there  
7 are some additions and retirements of OTC in our prescribed  
8 scenarios. In some cases, I think in most cases, what we  
9 have prescribed to retire and/or add for new capacity does  
10 not necessarily add enough for us to be able to just  
11 completely displace the operation of OTC units to meet our  
12 reliability requirements. And so, what I am showing here is  
13 the additional amount of capacity that we would have to add  
14 either through in-Basin generation capacity, or via  
15 increasing our transmission and ability to import. So when  
16 we look at the scenario and basically do a delta from there  
17 and say, well, we need more, or we do not need more,  
18 relative to what was described in that scenario. So in the  
19 low stress case for CAISO, what you can basically see is  
20 that, remember from our previous slide, we did not have much  
21 in the way of a retirement, and we did not have much in the  
22 way of new additions, other than Riverside at 96 Megawatts.  
23 So if that is all we do, what we are suggesting is that you  
24 still need an additional 2,000 Megawatts of capacity in the  
25 CAISO control area in order to allow you to essentially not

1 have to run those OTC units. The other caveat is something  
2 Richard mentioned earlier, and that is this number does not  
3 include San Onofre, so this does not include displacing  
4 SONGS yet. If you wanted to include that, it would be a  
5 pretty simple addition, you would just add about 2,250 to  
6 these numbers, so you can kind of keep that in the back of  
7 your head. But I think our implicit assumption was that  
8 that was not a unit that was going to be shut down or  
9 replaced by new capacity, it is a base load unit; rather, we  
10 would assume that we would either have an exemption, or it  
11 would comply. So one or the other. So that capacity at San  
12 Onofre is excluded from these numbers. That is something  
13 important to bear in mind.

14           So the bottom line is, what we are saying is,  
15 yeah, there is excess reserve margin in the CAISO control  
16 area, however, there is no so much excess reserve margin  
17 that I can just retire all my OTC units. I would still need  
18 to get a couple thousand Megawatts of capacity from  
19 somewhere, today, either new units, or new transmission, in  
20 order to meet reliability in the CAISO control area -- in  
21 the low stress case. In the high stress case, with a higher  
22 demand assumption, it is even more.

23           The other thing I will note is out here on the far  
24 right, you will see more of this in the future slides, and  
25 there is a little blue patch here. What that blue patch is,



1 is, again, with our scenarios, we took that as here is the  
2 prescribed capacity that we have. In some cases, that  
3 prescribed capacity that we put into the scenarios was  
4 enough to meet reliability, and in other cases it was not  
5 enough to meet reliability, regardless of whether or not OTC  
6 units are operated. So this blue line here basically says  
7 that, in 2018, the amount that we said we would add per this  
8 scenario, and retire for this scenario, did not result in  
9 enough capacity to meet the reliability requirements in what  
10 we assumed was a basic 15 percent planning reserve margin.  
11 And so there is a blue patch there that says, well, not only  
12 would I need more capacity to displace OTC, I would need  
13 even a bit more, yet, relative to what I prescribed in that  
14 scenario to meet the reliability requirements. That is  
15 important because you will see that blue show up quite a bit  
16 more in future slides.

17           What I have tried to do on the screen here is kind  
18 of show in color what is changing on the scenarios. We have  
19 a lot of scenarios we are looking at here, so what I am  
20 doing in going from this slide to the next slide, is I am  
21 only changing the assumption about what happens with  
22 transmission. It is still the low OTC retirement scenario,  
23 it is still the CAISO control area, but I am now going to  
24 say what if we then include all that new transmission that  
25 is in the plant? So when we do that, what you see is that,

1 in the low stress case, so if I make an assumption that I do  
2 not have a big demand growth and that I have got a lot of  
3 renewables coming in, you see the transmission gets us  
4 pretty much out of the woods, at least as far as replacing  
5 fossil fueled OTC capacity in the 2013 timeframe, in the low  
6 stress assumption. But, again, we cannot necessarily plan  
7 on winning the lottery, as Richard pointed out, and so we  
8 have to look at the high stress case, as well. And in the  
9 high stress cases, it says, no, you did not quite get there.  
10 You did not quite make it out of the woods just as a result  
11 of that new capacity coming online. So that is really what  
12 I want you to get out of this slide.

13           The next slide, I have kind of jumped, then, to  
14 changing the OTC retirement scenario, and now I have gone to  
15 the long run OTC retirement scenario, and I have then gone  
16 back to excluding new transmission. So the long run OTC  
17 retirement, as you will recall, had quite a few retirements  
18 and quite a bit of new capacity coming online. And, in  
19 fact, the net reduction in total capacity that is in-Basin.  
20 And, again, what we see in this situation is, if I replace  
21 all that capacity, repowerings and retirements with new  
22 units coming online, and so forth, again, I am out of the  
23 woods in the 2013 timeframe in the low stress case, but I am  
24 not out of the woods in the high stress case. And, again,  
25 when I say "out of the woods," I am talking about only from

1 a reliability and OTC operation perspective, not from an ERC  
2 perspective. ERC is later, and we will see those on future  
3 slides. I am not necessarily out of the woods on being able  
4 to acquire enough ERCs to put this capacity online.

5 So the next thing that I will change here is,  
6 again, jumping from excluding new transmission to including  
7 new transmission. So now what we see is, if I both retire  
8 quite a bit, I repower quite a bit, bring a lot of new units  
9 online, and allow that entire 3,200 -- assume that entire  
10 3,200 Megawatts of new capacity comes online, then in both  
11 our low stress and a high stress case, I am out of the woods  
12 from a requirement to operate those OTC units to meet  
13 reliability.

14 So the next -- we will basically walk through  
15 those same scenarios, same combination of scenarios, but for  
16 the LADWP control area, and what we will see is the  
17 situation is quite a bit different, or somewhat different in  
18 the LADWP control area. The first thing that we will note  
19 is that, at least by our analysis, again, with the publicly  
20 available data that we have, and using our analysis of  
21 transmission constraints and transmission congestion, our  
22 analysis indicates even today they do not necessarily have a  
23 15 percent planning reserve margin, and given that they have  
24 about, you know, almost 1,900 Megawatts of OTC, what you can  
25 take away from that is that, if I retire any OTC unit in the

1 LADWP control area, today, our analysis would suggest it has  
2 got to be replaced with something else. There is no extra  
3 in the LADWP control area, it is already tight. We do not  
4 have the benefit of the CAISO control area, which is up in  
5 the 27-28 percent reserve margin today, and then therefore,  
6 you know, some of that does not have to operate today. But  
7 they do not have that luxury, at least by our analysis, in  
8 the LADWP control area. So again, without any new  
9 transmission and with what we prescribed in the low OTC  
10 retirement scenario, they are not out of the woods in the  
11 entire timeframe that we have described.

12 Now, if I include new transmission, that is a  
13 different situation. The transmission plan, what we are  
14 looking at, is almost 2,400 Megawatts of new transmission  
15 coming in 2013, and basically that says that is enough to  
16 get you there. And if I jump back to that previous slide,  
17 you can sort of see why. If I look at this, I can see,  
18 well, gee, you are telling me I need about 2,000 and, in the  
19 highest case, maybe 2,100 in 2018 in the high stress case,  
20 but then I am going to add 2,400 Megawatts, right? So that  
21 should go away, and it does. So it kind of passes the dummy  
22 test there if we add that much capacity in transmission, you  
23 would be out of the woods from an OTC perspective and a  
24 reliability perspective in the LADWP control area.

25 Then the next two scenarios are actually very

1 similar, as you might imagine, because as I described  
2 earlier, the long run OTC retirement does not deviate  
3 significantly from the low OTC retirement scenario, so  
4 really the only difference we see is out here in 2018, where  
5 this is a little bit lower in 2018, but basically the same  
6 takeaways for the long run OTC retirement scenario, both  
7 including and excluding transmission as I have just  
8 described for these low OTC retirement scenarios, same  
9 conclusions there.

10           So again, that is getting us out of the woods on  
11 reliability and OTC capacity, but not from an ERC  
12 perspective. Just to summarize all those eight -- well,  
13 actually, 16 charts that you just saw, so, again, I  
14 appreciate that a lot of data, a lot of information being  
15 presented here, I tried to summarize that a little bit in  
16 just a table, and what we basically see is, if it is green,  
17 I have gotten out of the woods some time between now and  
18 2018, and if it is red, I have not, and, again, only from an  
19 OTC capacity and reliability perspective, but not  
20 necessarily from an ERC perspective.

21           COMMISSIONER BYRON: If I may? Green is good.

22           MR. WELCH: Green is good.

23           COMMISSIONER BYRON: Doesn't this also imply,  
24 then, that if you are building transmission, you are also  
25 addressing the ERC issue?

1                   MR. WELCH: Yes, and we will see on the next  
2 couple of slides that, whether I include or exclude  
3 transmission, that does have an effect on whether our  
4 ability to get out of the woods from an ERC perspective,  
5 certainly, if I add all that capacity with just  
6 transmission, then I am much better, obviously, from an ERC  
7 compliance perspective, rather than trying to add new  
8 generation. I mean, in an ideal world, we just add all the  
9 transmission we need, and then we would not have an OTC  
10 problem or an ERC problem, but right now it is indicating  
11 that, at least per the units and transmission plans, that  
12 does not always get us there. In some cases, it might. So  
13 I think it will be addressed on the next slide or two, if it  
14 is not, perhaps we can come back to that, or we can address  
15 it offline.

16                   So the bottom line is, in the CAISO control area,  
17 I am really only in the green, and if I have that new  
18 transmission assumed, and in the low stress scenario I am  
19 good in both the retirement cases, but in the high stress  
20 scenario, I am not good with the low amount of retirements,  
21 I need to retire something. In the LADWP case, we are  
22 basically saying, hey, you are out of the woods if you  
23 include a lot of new transmission, regardless of what we  
24 assumed on high stress, or low stress, or low OTC  
25 retirement, or a longer OTC retirement.

1           So the next couple of slides then get into the  
2 ERC's generator requirements. You have got about 10 minutes  
3 left, so I will get through these pretty quickly. Richard  
4 already described and you discussed what these values are,  
5 it is really -- we estimated the amount of ERC's that would  
6 be generated by retirement of OTC units, and then just used  
7 the amount that was requested in applications and so forth.  
8 What you can really just take away from this slide is that,  
9 really, on all of these slides, there is a net increase,  
10 really. The blue line is above the red line. So the amount  
11 that is being requested for ERCs in all these scenarios  
12 exceeds the amount we would expect would be generated by  
13 retirement of OTC units, and so therein we have got a  
14 problem because, in this case, there is a Delta of several  
15 thousand almost pounds per day, and I think I read somewhere  
16 in another presentation that there was maybe a grand total  
17 of a thousand on the market. So you cannot really get there  
18 from here. So we still have that as a problem.

19           And in the next slide, same situation for the  
20 LADWP control area. The net requests for that new capacity  
21 exceed the amount that you would expect to be generated. In  
22 this case, the red line is not very interesting, and that is  
23 because this red line is, again, based on the requests, and  
24 the requests that were provided for Haynes and Scattergood  
25 in the LADWP control area were net. In other words, they

1 applied or assumed that that 1304 exemption where you can  
2 just look at the net Megawatt change, they assumed that  
3 would be the case, they would not have to add that 900  
4 pounds per day that was shown on an earlier slide, it would  
5 net out to zero for Haynes and Scattergood, and so that is  
6 why the red line is zero there, because they are essentially  
7 requesting nothing. They are saying it is out, we are good,  
8 or a negligible small amount that does not show up on this  
9 graph. So, really, in the case, for instance, of Haynes or  
10 Scattergood, any amount that is new would show up in the  
11 blue line, but that is pretty much negligible for those two  
12 plants.

13 That being said, I will kind of let Richard jump  
14 back to conclusions, unless there are any questions on any  
15 of those slides I just presented.

16 MR. McCANN: Thank you, Cory. Just two last  
17 slides here. The first one is just talking about our  
18 conclusions. As Cory pointed out, we are finding the DWP is  
19 in a capacity short situation, regardless of what we are  
20 doing with OTC policy, so they are much more constrained  
21 than the ISO area is in terms of dealing with this issue.  
22 The other one is that, as new transmission lines come  
23 online, the ISO may have to specifically designate what type  
24 of power plants are running, and the reason why I bring this  
25 up is because of the inertial constraints and the ramping



1 requirements that have been talked about earlier. What has  
2 happened up to this point is that those requirements have  
3 been masked by the capacity requirements that have to be met  
4 in-Basin, and the new transmission lines relieve that  
5 constraint. So, now, new constraints arise and we are going  
6 to have to be much more specific about how we address those  
7 new constraints in the planning process. They have not been  
8 identified so clearly in the past as they need to be in the  
9 future. What the interesting thing is, that as we add  
10 transmission, it does appear to allow the retirement of OTC  
11 units, but again, it is contingent on meeting these various  
12 other operational requirements for which we would appreciate  
13 getting more information on those. And then, finally, there  
14 is going to have to be ways of dealing with acquiring ERCs  
15 beyond just retiring OTC units, there is going to have to be  
16 other sources of ERCs for meeting in-Basin generation  
17 requirements, regardless of the scenario that we are looking  
18 at.

19           And I just want to conclude with the additional  
20 data that we would desire to enhance this analysis. First  
21 is, specific operational nomograms like the SCIT, having  
22 numeric values, not graphs, from which you cannot really  
23 derive values, and other types of operational constraints  
24 like the blacked out graph that David put up of Orange  
25 County operational constraints, that sort of information is

1 necessary for doing further analysis. And that has to deal  
2 with minimum generation requirements and next-day commitment  
3 issues that affect OTC units. All these OTC units,  
4 basically they run 24 hours a day largely because they have  
5 to commit for running the next day to meet the loads, but  
6 that minimum generation has actually been used to meet other  
7 types of requirements and, as I mentioned, that capacity  
8 requirement has been masking that up to recently.

9           And then we also need more specific information on  
10 expected ERC generation and needed requirements at the unit  
11 level because most of the data is at the plant level. And I  
12 think that was about it for our list. I appreciate all the  
13 support we have gotten from the CEC staff on this, and  
14 appreciate being able to present this to you today. And we  
15 are open for questions.

16           COMMISSIONER BYRON: Very good. I suppose, given  
17 enough information, we can model anything. What we have  
18 asked you to do here is extremely complex and you have  
19 covered most -- many of the variables. And I think you  
20 mentioned this in the last couple of slides to some extent,  
21 but you know, these additional complexities -- ramping,  
22 inertia, stability -- if I was to look at your results, it  
23 seems to me I would tend towards the transmission solution,  
24 but when I have to consider these other things that you  
25 cannot model, at least at this point you are not able to

1 model, don't those emissions really decrease the value of  
2 the results of this work? Because, I mean, what we have  
3 heard earlier this morning is transmission comes in from the  
4 north, we need generation from the South to meet those load  
5 areas. You know, that kind of stuff, these ancillary  
6 services, doesn't that really devalue the results that we  
7 are getting here?

8 MR. McCANN: Well, what we started with in this  
9 analysis is that there was a belief that there was capacity  
10 requirements, in-Basin, that were needed, and that is what  
11 was keeping these plants online.

12 COMMISSIONER BYRON: Right.

13 MR. McCANN: And what we found in this analysis is  
14 that it is not the capacity that is doing that, so what we  
15 have done is we have been able to move beyond one layer of  
16 that type of analysis and say, okay, if we can solve the  
17 transmission problem, and that is a big "if" because, for  
18 example, DWP just announced that they are having second  
19 thoughts about the Green Path project, which is one of the  
20 big components that is in this analysis. So that sort of  
21 thing is important in terms of incorporating in our scenario  
22 analysis. But once you have that information, once you have  
23 those kinds of scenarios, yes, you probably can solve this  
24 with transmission, but transmission is not always an easy  
25 answer. And then we can move on to these other answers.

1 Now, the thing, for example, the inertial requirements, it  
2 is probably likely that we can get values that we can use in  
3 this model, and quite easily, with some discussions with the  
4 ISO and DWP about the inertial values in these individual  
5 units. And actually getting the underlined data for the  
6 SCIT, that sort of information, we could probably  
7 incorporate into this model and move on to another layer of  
8 analysis -- actually, quite easily. To be honest, we would  
9 not have to wait six months for an answer -- to answer that  
10 question sufficiently, to be able to move on to some other  
11 policy questions.

12 COMMISSIONER BYRON: Good. Well, I will look to  
13 staff to evaluate whether or not that is indeed the case,  
14 because we are looking for all the information and  
15 analytical tools we can get. Commissioner, before I open it  
16 up to others, do you have any questions?

17 VICE CHAIR BOYD: Actually, no. Mine have been  
18 answered. I am impressed, if not overwhelmed, but this  
19 information, it is very very useful and interesting, so  
20 thank you.

21 COMMISSIONER BYRON: Yes, sir, please identify  
22 yourself.

23 MR. KOSTRZEWA: Thank you. My name is Larry  
24 Kostrzewa. I am from Edison Mission Energy. Just following  
25 up on what Commissioner Byron was asking, it sort of looks

1 to me that, by ignoring ancillary services, and inertia, and  
2 ramping requirements, your analysis basically says, "If we  
3 repealed the laws of physics, this is how the numbers would  
4 work out," and you just need more data to factor in the laws  
5 of physics. Is that correct?

6 MR. McCANN: No, well, yes, we do need to factor  
7 in the laws of physics, but as I mentioned, really what this  
8 analysis was, again, it is about the fact that there was an  
9 initial premise that it was the in-Basin capacity  
10 requirements, the need to meet the peak load Megawatts,  
11 which was driving the requirement for OTC units. What our  
12 analysis shows is that is not necessarily the case, that it  
13 is this next layer of issues, of which these are arising,  
14 but if those can be revealed transparently, that we can  
15 address those issues further in the analysis. And one of  
16 the things that we found in this reduced form analysis, one  
17 of the things we found, for example, with the transmission  
18 capacity, is we were able to model the ISO and DWP  
19 transmission imports by looking at a reduced form model. We  
20 did not have to run the full blown transmission models in  
21 order to get the answers that we got. We were able to  
22 derive the important parameters and, by being able to derive  
23 those important parameters, you are able to get to answers  
24 that are reasonably approximately, reasonably close, in  
25 order to do policy analysis. I would not be doing

1 transmission planning or to add generation units based on  
2 this analysis, but you can address the question of what kind  
3 of constraints are you really facing, and which constraints  
4 do you need to relieve.

5 MR. KOSTRZEWA: But, in fact, it is the laws of  
6 physics that prevent transmission from solving the problems  
7 that you are saying transmission can solve.

8 MR. McCANN: Right, and so what we -- part of that  
9 is, is people assert that, and it would be useful to get the  
10 numbers so that we can look at that.

11 MR. KOSTRZEWA: I had one other question. Looking  
12 at your slide 16, you show about 3,000 Megawatts, a little  
13 over 3,000 Megawatts of transmission being added in the  
14 CAISO area in 2013. I assume that most of that is the  
15 Tehachapi project?

16 MR. McCANN: I would have to look. One of the  
17 things is that the ISO did not provide us an individual  
18 breakdown of units, so there is actually three large  
19 transmission projects that have all come online, and we do  
20 not know what the breakdown is between the individual --

21 MR. KOSTRZEWA: Well, I believe that most of that  
22 would be the Tehachapi project, and so it also matters what  
23 is on the other end of the transmission line --

24 MR. McCANN: Right --

25 MR. KOSTRZEWA: And at the end of the Tehachapi

1 Transmission project is wind generation, which counts for  
2 the net qualifying capacity for wind is about 9 percent of  
3 the nameplate, so 3,000 Megawatts of transmission capacity  
4 really only provides about 270 Megawatts of load carrying  
5 capacity.

6 MR. McCANN: That was already addressed actually.  
7 What we did is we took the ISO in its LCR tables for 2013  
8 produced -- estimated the amount of local capacity  
9 requirement that was needed in-Basin with the addition of  
10 transmission projects, and --

11 MR. KOSTRZEWA: But I think you are missing --

12 MR. McCANN: -- excuse me, what you can do is you  
13 can derive the amount of firm transmission capacity that the  
14 ISO is assuming is available to meet peak load requirements  
15 under 1 and 10 peak demand conditions, in each specific  
16 year. So this 2013 number is a number that the ISO derived  
17 itself for the amount of transmission capacity that is  
18 available to meet peak and load conditions. And if you have  
19 a problem with the 3,000 Megawatts, I would talk to the ISO  
20 about that.

21 MR. KOSTRZEWA: It is indeed Megawatts of  
22 transmission capacity, but on slides 21 and 22, that 3,000  
23 Megawatts of transmission capacity reduces the need for in-  
24 Basin capacity by 3,000 Megawatts, so you are effectively  
25 assuming almost 1 for 1.

1 MR. McCANN: The ISO is assuming 1 for 1.

2 MR. KOSTRZEWA: I do not think so.

3 MR. McCANN: Yes, it is. It is from their LCR  
4 table. Look in the LCR study, 2015 to 2013 LCR Study, and  
5 that is what the number is that they produced.

6 MR. KOSTRZEWA: Okay, thank you.

7 COMMISSIONER BYRON: Thank you.

8 MR. VAWTER: Hi, I am Don Vawter, I am with AES  
9 Southland. We own and operate 4,300 Megawatts of once-  
10 through cooling in the South Coast. Under your supply  
11 scenarios, you have El Segundo, Alamitos, and Huntington  
12 Beach repowering to some degree. And I was wondering if you  
13 were taking into account that those particular repowers  
14 would be exempt from ERC requirements under Rule 1304?

15 MR. McCANN: We were using the net numbers and I  
16 believe, Cory --

17 MR. WELCH: I know that to be the case for El  
18 Segundo, yes, it is the net numbers. I cannot speak off  
19 hand for the Alamitos situation, it may have been the plant  
20 by plant analysis where we received the net created, or the  
21 amount created from retirements, and the amount needed for  
22 new units. I do not know if that is the case for Alamitos,  
23 but I know that it is for El Segundo. We can look at that.

24 MR. VAWTER: Yeah, I think it would be interesting  
25 if you took a look at different repowering scenarios of OTC



1 units that were then exempt from the ERC requirements under  
2 1304, and then see where your ERC requirement is at that  
3 point. Thank you.

4 MR. McCANN: In most cases, we were using the net  
5 analysis, so we were looking at that repowering question  
6 from the net perspective in most cases.

7 MS. UNGER: Hi, Samantha Unger with Evolution  
8 Markets. We are an energy and environmental commodities  
9 brokerage firm. And my questions are actually related to  
10 the ERC slides. I am just wondering, because this is always  
11 a very touchy point when talking about ERCs generated from  
12 shutdown of facilities, or closure of plants, and in your  
13 numbers here in your model, I am wondering if this is really  
14 ERCs or, emission reductions, meaning not the actual number  
15 of credits generated, but the amount of emissions reduced.

16 MR. WELCH: Okay, it is our best estimation of  
17 actual ERCs and not just emissions, so we actually do look  
18 at the historical emissions of the unit, and there are  
19 certain multipliers that you apply, of course, depending on  
20 whether or not they operated less than 30 days, between 30  
21 and 180, between 180 and 365, so we use those multipliers to  
22 give our best estimate of actual ERCs generated, and not  
23 just emissions.

24 MS. UNGER: So you assume a BACT scenario here  
25 about Available Control Technology scenario?

1 MR. WELCH: Yes.

2 MS. UNGER: Based on today's technology?

3 MR. WELCH: That is my understanding --

4 MR. McCANN: Right.

5 MS. UNGER: Thank you.

6 MR. MICSA: Catlin Micsa, ISO. I would like to  
7 make a clarification. I think the information that the ISO  
8 has provided in our long term LCR results may have been a  
9 little bit misleading. Just by taking the total numbers  
10 from the overall requirements, it can give you a false sense  
11 of security, and what I am trying to say here is, yes, the  
12 requirements are decreasing a lot, starting in 2003 after we  
13 get a transmission problem, but what is happening is,  
14 actually, the pool of the units that are needed decreases a  
15 lot, as well, because we talked a little bit before that,  
16 right now, the binding problem is the entire LA Basin, it is  
17 basically south of Lugo, which has all the units in western  
18 and eastern help relieve that constraint. Once you build  
19 the transmission, almost the entire need shifts to the  
20 western area, so there is a much smaller pool of units than  
21 you can run from. So even though the requirement drops a  
22 lot for LA Basin, you can use the same amount of generation  
23 that you had before, and that table is misleading because --  
24 our fault -- it does include all the units in the existing  
25 LA Basin, we did not went in and told people how much are in

1 the west and how much are in the east by totals, and maybe  
2 that was a little bit misleading and they use the total  
3 number and, once you get to 2003 and beyond, you just might  
4 want to concentrate only on the western problems and just  
5 forget about the LA Basin. And that will give you a  
6 different result.

7           One other point I would like to make here is that,  
8 let's say we relieve the local constraints, that does not  
9 mean that the units are not needed. We could find ourselves  
10 in a position where we can relieve the local constraints and  
11 the units now -- the binding problem becomes the Southern  
12 California import transmission. Basically, the inertia we  
13 talked before, the ramping, that the requirement for the  
14 units might move from being needed from a local perspective  
15 to being needed for the entire Southern California. And,  
16 you know, the gentlemen talk about masking the problem --  
17 right now, so much is needed to meet local requirements,  
18 once we dispatch the units to meet that, most of the time  
19 you need Southern California import transmission, but if you  
20 start relieving the local constraints, you could end up in a  
21 situation where, yeah, it is not really needed from that  
22 local constraint anymore, but now you have a different  
23 constraint, which is Southern California import  
24 transmission. So just those two clarifications.

25           MR. McCANN: Yeah, and your presentation this

1 morning was informative about the west versus east because  
2 we were aware of it, but we did not have the data in order  
3 to address that, and so we did the model the way we did.  
4 But we appreciate that there is that important distinction.  
5 One issue about once you move to an SB 26 load serving area,  
6 you can now put generation outside of the South Coast,  
7 whereas if it has to be inside the LA Basin, it has to be in  
8 the South Coast. So that is an important thing to recognize  
9 in terms of policy options that you have.

10 COMMISSIONER BYRON: Please.

11 MR. TURNER: Hi, Mark Turner with Competitive  
12 Power Ventures. One more thing that I think is important to  
13 mention is that we are still looking at this a little  
14 piecemeal. Four days ago, I was in a meeting with Yakout  
15 Mansour with CAISO, and in that meeting, we were talking  
16 about the challenges of meeting the renewable portfolio  
17 standards in our greenhouse gas goals, and one of the things  
18 that was emphasized by Yakout is what we really need in  
19 order to go beyond the 20 percent goal and towards the 33  
20 percent goal, is this need for ramping capacity, ramping  
21 capability of units. And that is exactly the type of  
22 ancillary service that the new peaking facilities that are  
23 now under contract with SoCal Edison provide. And when you  
24 do an analysis like this and you are focused on OTC and  
25 transmission, and you leave out ancillary services, it is --

1 it is the can opener. It is missing. The can opener is  
2 gone, you know, I can be able to open the can and what the  
3 answer is. Yakout, you know, his emphasis was on ramping.  
4 Today we have had another individual from the CAISO talking  
5 about inertia capability and comparing that to, you know,  
6 the need for peakers. But the reality is, you know, a unit  
7 that provides excellent ramping flexibility and capability,  
8 by definition does not provide good inertial capability. So  
9 we need to fit all these pieces together, and I think if we  
10 just take what we have heard today in this meeting, we might  
11 walk away with a misinterpretation that, gee, we might not  
12 need these peaking units. But, you know, the analysis is  
13 not complete if you take in account the need of the  
14 ancillary services that are also very important for the  
15 system.

16 COMMISSIONER BYRON: Good. Those are all very  
17 good questions. You know, I have certainly never done a  
18 model or seeing a model, regardless of how good it was, that  
19 did not need more refinement or better assumptions, and so  
20 that is what I take away from many of the questions. There  
21 were questions asked that I would not even think of in terms  
22 of other refinements, other things we can do, but we are  
23 really going to look to staff for a determination of the  
24 value going further with this kind of work. I think it is  
25 informative, it does help us understand certain things, as

1 you indicated, but it is not just whether or not we can  
2 refine the model, can we get better input? Can we get  
3 better information? And for that, we need to rely upon the  
4 parties, as well. So I thank you very much. Commissioner,  
5 do you have any questions for these gentlemen?

6 VICE CHAIR BOYD: No, just a comment, Commissioner  
7 Byron. You are very wise for your youth, I notice, in that  
8 last comment.

9 COMMISSIONER BYRON: Why, thank you, Commissioner.  
10 Thank you, gentlemen.

11 MR. McCANN: Thank you.

12 COMMISSIONER BYRON: I think we will press on,  
13 then, because we are a little bit behind schedule. This is  
14 really excellent material. I think next is Mr. Nazemi from  
15 the South Coast Air Quality Management District, and we  
16 appreciate your being here. I suspect this presentation you  
17 have given many times before, if not to this Commission,  
18 certainly to many other bodies. Would I be correct in that  
19 assumption?

20 MR. NAZEMI: Good afternoon, Commissioner Byron.  
21 You are correct that I have been giving many presentations,  
22 and each one is a little different than the one I gave  
23 before because of the dynamic situation that we are in, in  
24 this case related to offsets.

25 COMMISSIONER BYRON: Right. Well, we look forward

1 to your candor, despite the fact that you brought your  
2 District Counsel with you here, as well, which maybe, I hope  
3 does not limit anything that you are able to say.

4 MR. NAZEMI: If it does, he will throw something  
5 at me.

6 VICE CHAIR BOYD: Mohsen, I thought you changed it  
7 all because the moving target is harder to pin down. Good  
8 to see you.

9 MR. NAZEMI: Thank you. Again, thanks for  
10 inviting me to speak at this workshop. I will try to give  
11 you a short presentation, and then I will be happy to answer  
12 any questions that you might have, either right now, or  
13 during the panel discussion. I think we all know why we are  
14 here, because we are looking at a requirement under federal,  
15 state, and local AQMD rules that, whenever there is a new or  
16 modified power plant that is proposed, that the offsets  
17 requirements needs to be evaluated. And under our local  
18 rules we have created over the last couple of decades, some  
19 exemptions from offsets for various reasons, some under Rule  
20 1309.1, referred to as Priority Reserve Rule, particularly  
21 those where the kinds of projects that was felt were  
22 considered as essential public service projects -- police,  
23 hospital, school, sewage treatment plant, and so on and so  
24 forth -- with one exception that, in the early 2000-2001  
25 energy crisis, we also allowed power plants to be

1 considered, with one big exception, that they had to pay for  
2 those offsets, unlike the others who got a fee, and the fees  
3 that were collected were reinvested in the emission  
4 reduction projects.

5           The other exemption we have under our rules is  
6 referred to as Rule 1304, you have heard about it a number  
7 of times today, and these are exemptions that, particularly  
8 for power plants, only apply if it is being repowered, one  
9 unit is replaced by another unit, or they are very small  
10 power plants. However, even though we have these exemptions  
11 in our rules, that does not relieve the requirements under  
12 federal, state law for the offsets requirements, and  
13 therefore our district has been providing the necessary  
14 offsets for these projects through what we call an internal  
15 offset bank, where we, the district, makes it whole by  
16 providing such offsets, even though the project proponents  
17 were not required to provide the offsets.

18           The status of power generation in South Coast, and  
19 I am not the expert in how much capacity is in the state,  
20 but if you look at the population of South Coast AQMD, you  
21 have over 16 million, almost half of the state population is  
22 in South Coast, and I think you can almost prorate the power  
23 generation to that. There is about half of generation  
24 capacity in South Coast, as well. For the existing units  
25 that are operating, almost half of that, actually a little



1 bit more than half of generation capacity, is actually 40  
2 years or older, and I do not want to put anybody on the  
3 spot, but in our assumptions, usually we assume an  
4 industrial facility operates for 30 years. Once it goes  
5 over 40 years, I mean, there are all kinds of issues  
6 relative to reliability, maintenance, and availability of  
7 the systems. In addition to that, you have heard about the  
8 State Water Resources requirements for once-through cooling,  
9 and when you look at the total generation capacity, again,  
10 one-third of the generation capacity is once-through cooling  
11 plants. So what we learned in the early California energy  
12 crisis in 2000-2001 was that there was concern that, for  
13 over a decade, you know, nobody had invested in new  
14 generation because the market was being changed and  
15 deregulated, and they were not sure what they were going to  
16 get for their money and investments, so once we hit the  
17 rolling blackouts and there was clear indication that there  
18 was a need for new generation, we did similar type of  
19 amendment to our rules, and we actually permitted, and today  
20 there are more than 5,000 Megawatts of clean air and state-  
21 of-the-art efficient units that were put in place since that  
22 time. However, at the same time, we noticed that over 3,000  
23 Megawatts of older, dirtier, and less efficient generation  
24 was retired. And the net effect was a better deal for the  
25 environment, even though we built more power plants, the

1 power plants that were built were cleaner and less  
2 polluting.

3           In 2006 and 2007, the District embarked on two  
4 actions that, even though they were done simultaneously,  
5 they really were totally independent. In '05, we were  
6 getting some analysis and estimates, projections from state  
7 agencies, the CEC, the ISO, that there was need for a new  
8 generation for three reasons, projected, demand, and growth,  
9 aged units, there were studies done about, again, the age of  
10 power plants in South Coast and other parts of the state,  
11 and the once-through cooling replacement that pretty much  
12 results in either repowering, replacement, or retirement of  
13 units. So we utilized that experience that we had from the  
14 early 2000 energy crisis, we did not want to go through that  
15 again and have diesel back-up generators run, or have power  
16 cut through essential services, and offered to amend the  
17 rules to allow power plants be built to meet the state and  
18 particular Southern California demand. So we allowed  
19 limited access for newer, cleaner, and more efficient power  
20 plants. We actually went beyond BACT, requiring new power  
21 plants to meet more stringent, both criteria and pollutant  
22 toxics emission limits, and requiring them again to pay  
23 greater emission mitigation fees that could be invested in  
24 the local areas where these power plants are going to be  
25 built. But at the same time, we were in discussions with

1 EPA, the district again to demonstrate that the projects  
2 that are exempt from offsets under our rules still meet the  
3 federal requirements. We were utilizing a tracking system  
4 that you have heard today from others refer to as the "old  
5 tracking system," or "previous tracking system," where we  
6 demonstrated that there was adequate amount of credits  
7 available to offset those emission increases, and therefore,  
8 even though our rule exempted it, they met the other  
9 requirements under federal/state law. And as a result of  
10 our discussions with EPA, they raised a number of issues  
11 about the tracking system and credits that were of concern  
12 to EPA. So in 2006 and following in 2007, we actually  
13 revised and updated our tracking system, and worked with EPA  
14 to replace some of the credits in our system that have been  
15 used in the past with other types of credits that EPA felt  
16 they were approvable under federal law, and therefore they  
17 were legal to be used.

18 Now, subsequent to that action, in both years, '06  
19 and '07, we were sued by a group of environmental  
20 organizations and, in July of 2008 and subsequently November  
21 of 2008, there was a state court decision that basically  
22 invalidated the amendments to Rule 1309.1 and the adoption  
23 of Rule 1315. And in that same order, it provided an  
24 injunction from using Rules 1304 and 1309.1 going forward.  
25 So as a result of that state court decision, the AQMD is not

1 able to issue any permits and use our internal offset  
2 tracking system to cover the emission credits for repowering  
3 and replacement of power plants. And I think this morning  
4 you had a little bit of a debate, which I know you do not  
5 like to have in this workshop, relative to whether or not  
6 the September 9<sup>th</sup> court decision actually allowed us to go  
7 back and use those old tracking system, and I think other  
8 than the discussion between the two counsels here, our  
9 counsel and the opposing counsel, I also want to point out  
10 that the Judge's Order just put a stay on the injunction,  
11 and it did not modify the Order. So when the state expires,  
12 we are back in the same boat. But most importantly, we  
13 cannot rely on the old tracking system because EPA had  
14 raised issues relative to the credits that were used and the  
15 tracking system that was used before, and that is the whole  
16 reason why we revised it, and updated it, and they also  
17 wanted us to adopt it into a regulation to memorialize it,  
18 and we did that. But I am a little bit disappointed that I  
19 hear the plaintiffs argue that not only you can use the old  
20 tracking system, and that is what the court ordered you to  
21 do, where they themselves have sued us in federal court  
22 about the validity of credits in the old tracking system.

23           So as a result of this court decision, we believe  
24 that the only way that power plants can use -- to obtain  
25 permits from the district at this point is the use of ERCs

1 that are available in the open market. The problem with  
2 that is that, 1) there is not enough in the open market, and  
3 2) that their prices are such that they are potentially  
4 unaffordable. If you look at just the history of what the  
5 ERCs availability and prices are for PM-10 in South Coast,  
6 you can see the white bar starting from the left, going to  
7 the right, shows the availability of those credits, and  
8 between 2000 and 2009, the availability have dropped by  
9 almost one-half. And what is left actually, it shows about  
10 1,000 pounds per day, but in reality not all 1,000 pounds  
11 per day is in the market for sale. There are companies that  
12 do not fall under any one of these exemptions under 1304 or  
13 1309.1, and if they need to expand, they have to buy ERCs,  
14 so they have those ERCs to use for their own projects. In  
15 addition to that, you will see the price of the ERCs between  
16 2000 and 2009 has increased by 700 times. That is close to  
17 700 or 70,000 percent -- not 700 percent, not 70 percent --  
18 70,000 percent. As a result, I think the notice for this  
19 workshop was citing that the prices of ERCs in South Coast  
20 has reached as high as \$135,000 or \$150,000 per pound, per  
21 pay. Actually, the last price of ERCs that the transactions  
22 took place were three government agencies, the City of Los  
23 Angeles, the City of Ontario, and the City of Anaheim, that  
24 they bought PM-10 ERCs at prices ranging somewhere between  
25 \$310,000 to \$350,000 per pound, per day.

1           So if you just took the three projects that you  
2 heard this morning from Edison and some of the project  
3 proponents that they have obtained contracts from, Edison  
4 approved by PUC, the amount of credits that they need is  
5 twice as much of ERCs that is out in the open market. Now,  
6 when that presentation -- Mr. Minick gave his presentation  
7 and subsequently I think Mr. McCann from Aspen made his  
8 presentation, they argued that, "Well, maybe we really don't  
9 need that much ERCs, you need maybe only 600 pounds per day,  
10 or 700 pounds per day, or whatever number of pounds per  
11 day." I want to make it clear that we would not require  
12 more ERCs than what the applicant asks us to be able to  
13 operate, so Commissioner, you are absolutely correct that,  
14 if they ask us that they only wanted 800 pounds per day  
15 ERCs, that is what we would require. The problem is that  
16 some of the members who are going to talk this afternoon, or  
17 have already talked, are assuming that we are going to  
18 change our rules and New Source Review requirements to, in  
19 effect, change how ERCs are to be calculated. And I want to  
20 point out that there is state law, referred to as SB 288,  
21 that will potentially raise issues every time we go to  
22 change our New Source Review rule, it needs to go through a  
23 hearing through the Air Resources Board, and submittal to  
24 EPA with SIP approval, and those are not as easy as they  
25 sound, like just go out and change your rule. First of all,

1 it has to be a change in our rules, and second of all, we  
2 think there are issues related to state law that need to be  
3 addressed there.

4           And then, secondly, I want to also comment on Mr.  
5 Vidaver's presentation earlier this morning where he showed  
6 a list of three projects that have obtained contracts with  
7 Edison, and then the list of projects that I believe in the  
8 slide were referred to as plants waiting without contract.  
9 And I noticed in that list, there were two projects listed,  
10 City of Vernon, and AES High Grove, and I know that there is  
11 a scheduled hearing for the City of Vernon on October 19<sup>th</sup>,  
12 so I -- and there is a chance that it may not happen, but I  
13 want to make it absolutely clear that our agency has denied  
14 permits for both of those projects. As of today, the  
15 counsel for the City of Vernon, who has appealed the denial  
16 of the permit, has declared to the Hearing Board that they  
17 are withdrawing their application for the appeal. So with  
18 that announcement, I want to make it clear to the Energy  
19 Commission and others here that we have no applications on  
20 file for these two projects, so I am not sure when you say  
21 they are waiting -- what are they waiting for? Because one  
22 of the primary determinations relative to most power plants  
23 is air quality determination, and our determination of  
24 compliance is that there is no application to determine any  
25 compliance.

1           VICE CHAIR BOYD: Mohsen, just for your  
2 information, I was reluctant to say anything as the  
3 Presiding Siting Commissioner on South East Regional/Vernon,  
4 that we are aware -- we have been informed by their counsel,  
5 you may want to verify this later, but they intend to  
6 withdraw their application. But that is late breaking news,  
7 frankly.

8           COMMISSIONER BYRON: And the other one you  
9 mentioned, was it -- did I hear you correctly -- High Grove?

10          MR. NAZEMI: AES High Grove. We denied their  
11 permit and they did not even appeal our denial.

12          COMMISSIONER BYRON: All right, thank you.

13          MR. NAZEMI: So, aside from these other power  
14 plants that we are all here to talk about, I wanted to point  
15 out that our inability to issue permits under 1304 and  
16 1309.1 affects other projects that are, to me, power plants.  
17 And these are renewable projects. I just listed three of  
18 them here on landfills in Irvine, Brea, and Sylmar that,  
19 together, they add up to about 75 Megawatts of renewable  
20 generation. Last week, we received an application for a 500  
21 Megawatt solar power plant called Solar Millenium Plant, to  
22 be located 10 miles east of Desert Center in our  
23 jurisdiction. This plant actually requires, and I have  
24 since -- I prepared a slide, it has been recalculated --  
25 this plant requires about 11 or 12 pounds of PM-10 ERCs, so



1 if you look at these other projects, they cannot go forward  
2 unless they supply their own ERCs also, and it will cost  
3 anywhere from \$6 to 100 million to get those ERCs. So I  
4 think the focus of the Energy Commission right now is the  
5 projects that are in front of them, but there are other  
6 projects that are going to help the grid, but they are not  
7 going forward.

8           So, Commissioners, I think today's workshop -- and  
9 I really thank you for holding this workshop -- is a very  
10 good example why our agency has decided not to amend 1309.1  
11 for power plants anymore. We believe that this task is the  
12 state agencies' who have expertise in energy planning,  
13 transmission lines, generation, and demand forecasts. We  
14 tried to help the Southern California region when we were  
15 told that there is a crisis coming, but I think it reminds  
16 me of an old cartoon in the newspaper where the global  
17 warming was not as prevalent as it is today, where they were  
18 holding a seminar on global warming, and there were people  
19 sitting in Eskimo suits on one end of the table, all the way  
20 to in their swimsuits at the other end of the table, and  
21 these were all the expert panels. So I think your -- I do  
22 not envy your job, but there is a need for the experts to  
23 get together and put their heads together and, as  
24 Commissioner Byron, you stated, be open and share  
25 information so everybody can understand what assumptions

1 were used to drive conclusions. And it is really important  
2 to do that.

3           So what are we doing, though? We are continuing  
4 to proceed with the re-adoption of Rule 1315. We are  
5 expecting that some time in the first quarter of next year,  
6 we will be able to do that, but what is important at this  
7 point is there is proposed legislation that has passed  
8 through both Assembly and Senate, awaiting the Governor's  
9 signature under Senate Bill 827, that if signed into law  
10 will allow us to use the old tracking system, which  
11 everybody says is good to use, but have enough credits in  
12 it, not just use the old system, but have enough credits in  
13 it to be able to stand behind the permits that we issue.  
14 Without that, as of today, the permit moratorium is still in  
15 effect, so I wanted to make it clear to folks from LADWP  
16 that we are not ready to issue their permit for Haynes  
17 because we do not believe that we can do that without having  
18 adequate credits in the market.

19           COMMISSIONER BYRON: So you just mentioned the one  
20 piece of legislation on your slide. Are you endorsing both?  
21 Or either of these, I should say? Or just the Wright Bill?

22           MR. NAZEMI: Commissioner, I believe you are  
23 referring to Perez Assembly Bill 1318. That is specific to  
24 one single power plant and I think we are really asking --  
25 not asking, but we are supporting SB 827 because we need a

1 global solution to permit moratorium.

2           My last two slides are really a response to the  
3 comments or questions that were part of the notice for this  
4 workshop, and that is what else we need to worry about. I  
5 think we all know that there is a new national MN quality  
6 standard for the fine particulates which is smaller than PM-  
7 10, referred to as PM-2.5, this standard was adopted in 2006  
8 by EPA, and as of this date, the final rule was issued in  
9 May, and it has a three-year sunset -- not sunset, but  
10 implementation deadline. So the effective date of the rule  
11 was July of 2008, and we have until July of 2011 to  
12 implement a PM-2.5 into our new source review program and  
13 into the State Implementation Plan. However, having said  
14 that, South Coast is one of the only two areas of non-  
15 attainment for PM-2.5 under new federal standard. The other  
16 portion of the South Coast Salton Sea and Mojave Desert Air  
17 Basins are attainment, but South Coast Air Basin, which is  
18 the majority of projects we are talking about here, is non-  
19 attainment. And under the EPA PM-2.5 rule, we are required  
20 to use what is referred to as Appendix S, which is kind of  
21 like EPA's non-attainment New Source Review Rule, to use  
22 that Appendix S in the mean time, until we implement it into  
23 the SIP for permitting of any PM-2.5 source. And the way  
24 the source is defined under the federal law is any facility  
25 that has potential to emit 100 times per year or more of PM-

1 2.5. So if any of these power plants, existing or new, that  
2 are undergoing permitting, if they are a major source of PM-  
3 2.5, then we would have to address that, and one of the  
4 requirements under the Appendix S for PM-2.5 is requirements  
5 for offsets.

6 And the last item that I wanted to point to is the  
7 greenhouse gas global warming requirements that, under the  
8 Federal EPA endangerment finding that was issued in April of  
9 this year, they identified six greenhouse gases, including  
10 carbon dioxide, as contributing to air pollution that may  
11 endanger public health or welfare, there is the federal  
12 Waxman-Markey Bill that, under Title 1, has requirements for  
13 renewable combined efficiency standards, and there is the  
14 state, of course, AB 32 Scoping Plan requirements for the  
15 renewable 33 percent and cap-and-trade that would begin with  
16 electricity generation in large facilities in 2012. That  
17 pretty much concludes my presentation, but I would like to  
18 ask Oscar Abarca, our Deputy Executive Officer for Public  
19 Affairs, to also make a conclusory statement.

20 MR. ABARCA: I just want to clarify a statement  
21 that Mohsen made to answer your question, Commissioner, and  
22 that is that, with respect to the AQMD's position on SB 827  
23 and AB 1318, our agency, the South Coast Air Quality  
24 Management District, is the sponsor of SB 827, and we  
25 support AB 1318 because it has the correct language that

1 would allow us to access credits from our bank, to be able  
2 to issue to that one power plant. Thank you.

3 COMMISSIONER BYRON: Thank you. Commissioner?

4 VICE CHAIR BOYD: Just a quick comment. Mohsen,  
5 good to see you. I appreciate your kind words about the  
6 need for and the capabilities of the energy agencies to deal  
7 with this issue, but I suspect that, if not you, your boss  
8 delights in delegating the problem upward to these energy  
9 agencies. You can tell Barry that we recognize the fun we  
10 are all going to have with this. Thanks, it was a very  
11 enlightening presentation.

12 MR. NAZEMI: Commissioner, I appreciate that and I  
13 will pass it on to Barry, but I think it was partly as a  
14 result of the Judge's state court decision that she wanted  
15 our agency to do the analysis that you are hearing five  
16 different agencies debating over, as part of our rule  
17 amendment, and we have no expertise to do that kind of  
18 analysis.

19 COMMISSIONER BYRON: Mr. Nazemi, thank you for  
20 being here. A quick question if I may, going back early in  
21 your presentation, you know, you made the comparison back to  
22 2000, 2001, when we retired more than 5,000 -- I am sorry,  
23 we built more than 5,000 Megawatts of generation, while  
24 retiring 3,000 Megawatts, and I believe you said the net  
25 effect was an improvement for the environment. Would that

1 be the case going forward if we were to build new efficient  
2 power plants and retire the aging ones that exist on the  
3 coast?

4 MR. NAZEMIU: On a pounds per Megawatt hour basis,  
5 yes. Now, if you want to sit down and look at each plant, I  
6 mean, we heard today some of them may have lower capacity  
7 than others, and we also heard at the same vein that the new  
8 power plants that are asking to run X number of hours, they  
9 do not really need that many hours. So it depends if you do  
10 an apples to apples comparison in terms of pounds per  
11 Megawatt hour, yes, the new plants are more efficient. You  
12 take a utility boiler that is only 29 percent -- has 29  
13 percent efficiency -- compare it to even a simple cycle gas  
14 turbine that has over 58, 59 percent of efficiency, you can  
15 see that you will burn less gas and PM-10 is -- or PM-2.5 is  
16 the result, the direct result of burning natural gas. So if  
17 you want the same amount of Megawatts, you are going to be  
18 burning less gas to generate it.

19 COMMISSIONER BYRON: Thank you very much. Dr.  
20 Jaske was the first to the microphone, although I see we  
21 have a few others behind him. Please go ahead.

22 DR. JASKE: For the record, Mike Jaske. Your  
23 slide, third from the last, the supplemental comments of  
24 your colleague, raised SB 827 and I guess I am struggling to  
25 reconcile what you said about 827 with another part of your

1 presentation. I believe 827 points you back to the pre-1315  
2 offset tracking system, which I guess from state law  
3 perspective is sanctioning. But I also heard you say that  
4 USEPA was not happy with the pre-1315 internal bank tracking  
5 system, so will USEPA, in effect, sign off on a permit for a  
6 plant pursuant to SB 827?

7 MR. NAZEMI: Mr. Jaske, I cannot speak for USEPA,  
8 obviously, but the concerns that EPA had with our previous  
9 tracking system were related to some, in most part, to some  
10 pre-1990 credits, and as part of our agreements with EPA, we  
11 retired 93 percent of PM-10 pre-1990 credits that we had no  
12 longer maintained records for. And whatever remaining pre-  
13 1990 credits there were in the bank for all pollutants, we  
14 also retired in 2005. So the reason I -- and, by the way,  
15 state law or state court did not sanction the use of the  
16 previous tracking system, they sanctioned the use of 1315  
17 tracking system. What I was trying to explain is that, if  
18 we go back to the previous tracking system, where we agreed  
19 to eliminate a major portion of the credits, a significant  
20 portion of the credits, and with EPA's agreement putting in  
21 place of those some new credits that were always credible  
22 and available to use, then you are going to find a bank that  
23 does not have enough credits to move forward to issue  
24 permits to anyone. So, as a result, the amount of credits  
25 that will be granted to LADWP or anybody else will not be

1 supported by the old tracking system.

2 COMMISSIONER BYRON: Mr. Nazemi, I see another  
3 clarification coming forward.

4 MS. BAIRD: If the Commissioners would indulge me,  
5 I think Mr. Jaske -- or Dr. Jaske -- was asking, since SB  
6 827 also refers to the old tracking system, why do we  
7 believe SB 827 gives us relief and allows us to go forward  
8 and issue permits. And the reason for that is SB 827 also  
9 says, in addition to the old tracking system, the District  
10 can use any emission reductions from minor source emissions  
11 reductions or minor source shutdowns that have occurred  
12 since 1990. We can rely on those credits to begin issuing  
13 permits. And those are the credits that we have relied on  
14 to replace the pre-1990 credits that, as Mohsen was  
15 explaining, we have discarded per our agreement with EPA.  
16 So that Bill gives us the mechanism to take account of the  
17 credits that have occurred since 1990, that meet federal  
18 requirements, and use them to rely on for issuing permits in  
19 the future. Thank you.

20 DR. JASKE: Okay, so if I understand what both of  
21 you have said, it is that this proposed legislation, or this  
22 bill that has passed the legislature, awaiting the  
23 Governor's signature, will recreate the legal pathway to  
24 provide internal credits to power plants, but that there is  
25 a very limited amount of such credits that are, in fact,



1 available?

2 MR. NAZEMI: Two clarifications, it does not allow  
3 credits to go to new power plants, only to repowers --

4 DR. JASKE: Oops, yeah, I am sorry I said that  
5 wrong.

6 MR. NAZEMI: -- and second, the answer is, yes,  
7 there will be adequate amount of credits for power plants  
8 and all other essential public services and other projects  
9 exempt on their Rule 1304.

10 DR. JASKE: Thank you.

11 COMMISSIONER BYRON: Thank you. Please.

12 MR. VAWTER: Thank you. Don Vawter, AES  
13 Southland. Well, it is correct that the District did deny  
14 the permit application for AES High Grove. Really, we kind  
15 of gave up on that project. The District had asked us to  
16 demonstrate how we would come up with the ERCs to keep that  
17 project going forward. They were very patient with us, they  
18 gave us a couple of extensions, but at the end of the day,  
19 we could not do that and they said it was time to either  
20 demonstrate, or they would have to deny the permit  
21 application. We told them that was the appropriate thing to  
22 do at the time, so we would like to say we quit before we  
23 got fired. I just wanted to clear that up. We now look  
24 forward to working with the District as we intend to repower  
25 most of our 4,300 Megawatt OTC portfolio over the next 15

1 years, and our path forward is the 1304 exemption. Thank  
2 you.

3 COMMISSIONER BYRON: Good, thank you for the  
4 statement.

5 MR. MARTINEZ: Good afternoon. My name is Adrian  
6 Martinez and I am here on behalf of Natural Resources  
7 Defense Council. And I just had a quick question for the  
8 Air District. Does the Air District believe that the  
9 provisions of 827 allowing for use of minor source emission  
10 reductions needs to undergo EPA approval before being used?

11 MR. NAZEMI: We had already discussed the use of  
12 minor source shutdowns with EPA in a letter they had, in  
13 concept agreed with us using those. So we will provide it  
14 as part of Rule 15 re-adoption to EPA, but there is no  
15 concern raised to us by EPA relative to those minor source  
16 shutdowns.

17 COMMISSIONER BYRON: Mr. Carroll?

18 MR. CARROLL: Good afternoon. Mike Carroll with  
19 Latham and Watkins, and I also wanted to address this  
20 particular issue of what EPA has said, or what EPA has  
21 required because, in fact, what EPA has indicated is that it  
22 believes that it would be preferable for the tracking system  
23 to be reflected in a rule; however, they have never said  
24 that that was a requirement in order for the offsets being  
25 made available pursuant to the District's tracking mechanism

1 to be federally enforceable. They have never disapproved a  
2 permit on the basis of the absence of the rule to date, they  
3 have never disapproved a district rule that made offsets  
4 available from that internal emission offset account based  
5 on the absence of the rule, so it is true, EPA does want to  
6 see a rule, but they have never said that the district  
7 cannot move forward, or that the credits that are in the  
8 District's internal emission offset accounts are not valid  
9 and available for use in satisfaction of all federal  
10 requirements until such time as that rule is in place. In  
11 fact, when they have gone on record in an official way, and  
12 spoken on the issue, they have said just the opposite. In a  
13 Federal Register Notice approving District Rules, what they  
14 said is that improving Rule 1309.1 in 1996, we, EPA,  
15 determined that the District's implementation of a tracking  
16 system demonstrated that the priority reserve bank's  
17 emission reduction credits complied with the requirements of  
18 Section 173C. And, again, in a letter dated April 11<sup>th</sup> of  
19 2006, the EPA said -- this is a letter from Deborah Jordan  
20 of Region 9 to Barry Wallerstein of South Coast AQMD -- "We  
21 have reviewed the District's proposed revised NSR offset  
22 tracking system and believe that the system now addresses  
23 underlying historical issues such as the use of the pre-1990  
24 credits, credits for the District's BACT discount, and the  
25 need to adjust aging credits retained in the system." They

1 then go on that letter to say, "We look forward to seeing a  
2 rule," but they have never said a rule is required. And  
3 their actions clearly indicate that they do not believe a  
4 rule is required. Thank you.

5 COMMISSIONER BYRON: I thought that comment might  
6 elicit a response.

7 MR. NAZEMI: Thank you very much.

8 COMMISSIONER BYRON: Thank you. Thanks for being  
9 here and we appreciate the expertise that you brought with  
10 us, very helpful to have answers to these questions and the  
11 insight -- the latest insights that we are looking for.

12 All right, next is the Developer Observations on  
13 ERC Procurement and Requirements. And on the agenda, I show  
14 Mr. Larry Kostrzewa from Edison Mission Energy.

15 MR. KOSTRZEWA: Thank you very much.

16 COMMISSIONER BYRON: Did I say that correctly?

17 MR. KOSTRZEWA: No, but nobody does. It is really  
18 okay.

19 COMMISSIONER BYRON: I apologize.

20 MR. KOSTRZEWA: Happens all the time.

21 COMMISSIONER BYRON: Please correct me.

22 MR. KOSTRZEWA: It is Kostrzewa.

23 COMMISSIONER BYRON: Thank you.

24 MR. KOSTRZEWA: Well, I come from the perspective  
25 of being a developer to quick start fast brown peakers in

1 the LA Basin Local Reliability Area that we have developed  
2 to meet the needs that the various agencies and utilities  
3 have projected. One of them is the Walnut Creek Energy  
4 Park, and that one has a Final Determination of Compliance  
5 from the Air District, the final license from the CEC, and  
6 the power contract from Southern California Edison. We have  
7 a Bill similar to AB 1318 that made it through the Assembly,  
8 but not quite through the Senate, and so we look forward to  
9 completing that when the Senate resumes so that we can meet  
10 our PPA commercial operation date in 2013. The second  
11 project is one that has got a Final Determination of  
12 Compliance and a Preliminary Staff Assessment, but of course  
13 got held up in the permit moratorium. And, really, that is  
14 most of the thoughts that I will be expressing from that  
15 perspective.

16 COMMISSIONER BYRON: And just, if I may for  
17 clarity, which project is that?

18 MR. KOSTRZEWA: The Sun Valley Energy Project in  
19 Riverside County.

20 COMMISSIONER BYRON: And so, I am sorry, I am a  
21 little slow on the uptake, so the problem with the Walnut  
22 Creek one is you still need ERCs, correct?

23 MR. KOSTRZEWA: Well, that is the problem with  
24 both of them. We hope -- or we anticipate Walnut Creek  
25 probably being resolved through legislation.

1           COMMISSIONER BYRON: Well, it had everything else,  
2 it was just the ERCs.

3           MR. KOSTRZEWA: Correct.

4           COMMISSIONER BYRON: Okay.

5           MR. KOSTRZEWA: And the Sun Valley Project,  
6 obviously there are lots of presentations and lots of  
7 viewpoints, but bottom line, there is 5,600 Megawatts of  
8 capacity in the LA Basin Local Reliability Area that  
9 averages about 47 years old, and that is pretty old for a  
10 power plant. There are also not quick ramping or fast start  
11 and, you know, I am sure you understand that wind generation  
12 in California is primarily an off-peak resource which, when  
13 you have got power plants that have to stay on all night in  
14 order to be available for the day-time peak, that results in  
15 an increasingly more serious -- or over-generation problem  
16 at night, and already this year, in June, we had negative  
17 power prices as a result. And additional wind is just going  
18 to make that problem greater, so we really need capacity  
19 that can turn off when it is not needed.

20           From our perspective, a competitive market is key  
21 and for a competitive market to work, you have got to have  
22 multiple options that are permitted and ready to go. It is  
23 very dangerous to rely on permitting projects after the need  
24 is already identified. We really saw that during the  
25 California power crisis. We need to have those options

1 ready and available, and then can pull the trigger on them  
2 when the need is actually there. And really, there has to  
3 be more projects permitted than will ultimately be built,  
4 otherwise there is no competition. You have just whatever  
5 has been permitted is your only option. And because of the  
6 scarcity of PM-10, and do not forget SO<sub>x</sub>, ERCs in the South  
7 Coast Air Basin, we agree that some new thinking and  
8 policies would be called for.

9 I want to talk a little bit about some of the  
10 questions that were raised both in the discussions and in  
11 the panel question. One is the number of hours. Certainly,  
12 if you are building a peaking plant to solely meet resource  
13 adequacy obligation, the number of operating hours can be  
14 deeply limited. More efficient turbines, which in order to  
15 address the global warming problems, really need to operate  
16 more hours because they have an energy value besides just  
17 the resource adequacy value. And so they will tend to  
18 operate more and I will show you a chart on that in must a  
19 moment.

20 The cost is pretty amazing for these -- 400 or 500  
21 Megawatt peaker. The ERC package would cost \$50 to \$80  
22 million. Those are not real prices, it is scarcity, so it  
23 is whatever the market will bear. And when you look at  
24 that, that adds over 10 percent to the capital cost of  
25 building a peaker in the South Coast Air Basin. And when

1 you are talking about those kind of dollars, it obviously  
2 does not make sense for a developer to purchase the ERCs,  
3 even if we could, which we cannot, just not that many are  
4 offered, and hang on to them in hopes that in some number of  
5 years down the road, we will be able to build a plant. So  
6 the need to have multiple options ready to go and the  
7 reality of the costs involved, just -- that does not work.  
8 And even if we could, having a bunch of power plants holding  
9 all those ERCs would only exacerbate the shortage if they  
10 were available, and they are not.

11           The Rule 1304 exemption for electric utility steam  
12 boiler replacements is only available to three suppliers in  
13 the South Coast Air Basin -- AES, NRG, and Reliant. And  
14 that does not provide enough competition to assure the least  
15 cost to ratepayers, so we need solutions beyond just Rule  
16 1304. Some parties have suggested that, well, power plant  
17 shutdown credits could be a solution, but it is not, really.  
18 The new plants must be built before we shut down the old  
19 plants, so there is a timing problem. Secondly, the Air  
20 District's rules for determining how many shutdown credits  
21 you can qualify for are really designed to minimize the  
22 supply of credits, but the offset rules that we have to  
23 follow to build a new one are really designed to maximize  
24 the need for those credits, and so there is just a  
25 fundamental mismatch there, too. And lastly, again, power



1 plant shutdown credits, they are just essentially a three-  
2 party oligopoly there.

3           There are a bunch of solutions. I put up here an  
4 excerpt from a slide that the Air District shared with their  
5 NSR Working Group, and we really encourage them to keep  
6 working on that, it is great out-of-the-box thinking, and  
7 that is what we need. I circled a few of those, and those  
8 are the ones that I will address going forward.

9           COMMISSIONER BYRON: Forgive me, NSR -- is that  
10 New Source?

11           MR. KOSTRZEWA: New Source Review, I am sorry, I  
12 broke the acronym rule already. Here is a chart that we  
13 pulled together from some data that the Energy Information  
14 Administration publishes. It shows capacity factors of  
15 power plants in Southern California plotting their capacity  
16 factor against their heat rate. And I think it refutes,  
17 first of all, the idea that the existing units in the Basin  
18 are efficient. As you can see, the existing units are the  
19 ones off to the right that are actually quite inefficient.  
20 And the red line there represents the GE LMS 100 turbine  
21 that we are planning to use for our Sun Valley project. It  
22 is quite a bit more efficient than the existing stock. And  
23 although it is hard to draw a line through all those points,  
24 you can see, as the plant gets more efficient, it is  
25 economic to run more. The question of exactly what capacity

1 factor the plant will run at will depend on the weather --  
2 is it a hot year, or a cold year? How much hydro do we have  
3 from the North? And various other factors. But in order to  
4 have a useful asset in the LA Basin, we do have to permit  
5 for the extreme condition.

6 And this table here attempts to really illustrate  
7 the impact of all those assumptions. There are a lot of  
8 numbers there and I will try to walk you through line by  
9 line.

10 COMMISSIONER BYRON: You know, I am just going to  
11 ask you if you could go back to that last slide just a  
12 second.

13 MR. KOSTRZEWA: Certainly.

14 COMMISSIONER BYRON: The way you made the  
15 statement, that you have got to develop the project for the  
16 extreme condition, but I think the other way we have been  
17 hearing that statement made is that what you need to ask for  
18 is you need to ask for a lot of ERCs because you might need  
19 to run a lot more than 10 or 20 percent of the time.

20 MR. KOSTRZEWA: That is right. What are we going  
21 to do if it is a hot summer and it is dry hydro year like we  
22 had in 2001? You just have to run all those hours. It  
23 would be bad if we say, "Sorry, we're not permitted to run  
24 anymore hours."

25 COMMISSIONER BYRON: All right.

1           MR. KOSTRZEWA: So this next slide looks at really  
2 how our -- how Sun Valley's PM-10 offset requirements are  
3 determined. Starting with what we think will happen, the GE  
4 turbine will probably emit about 4 pounds per hour for each  
5 turbine of particulate emissions, but GE, being cautious, of  
6 course, will only guarantee 6. But if we could offset based  
7 on our expected operation, and we plan on a 1 and 2 summer,  
8 a typical summer, we have maybe a capacity factor of 20  
9 percent, looking at kind of a high number from the prior  
10 chart. If we could average the quantity we would need over  
11 the whole year, we on average over the year would emit 102  
12 pounds per day, and multiply that by 1.2 and we would need  
13 122 pounds per day. Well, in fact, we are uncomfortable  
14 permitting at the emissions we expect. We want to permit at  
15 the emissions that are guaranteed because we need to get  
16 bank financing, and the banks will say, "Well, guarantee me  
17 that you are going to meet it." So we have to use the 6  
18 pounds per hour. Well, the result of bumping up to 6 pounds  
19 per hour is now we need 183 pounds per day of the ERCs.  
20 Well, another factor, too, is, to be a useful resource in  
21 the Basin, we need to plan not just for an average summer,  
22 we need to plan for the 1 in 10 summer, which I think was  
23 mentioned in one of the earlier slides. In a 1 in 10  
24 summer, at least our calculations suggest, the plant might  
25 have to operate 35 percent of the year -- not ever often,

1 only once every 10 years, but it could happen. Well,  
2 suddenly our offset requirement jumps to 313 pounds per day.  
3 Add to that, now, the requirement in the Air District's  
4 interpretation of their rules that the offset requirement  
5 needs to be based on not the year as a whole, but the  
6 maximum month, which of course for a peaker is July and  
7 August. Well, if we want to operate during the entire on-  
8 peak period in July and August, that is 16 hours a day, six  
9 days a week, that bumps the offset requirement to 525 pounds  
10 per day. That would be 59 percent of the time, you know, as  
11 an extreme case, we hope it would never happen, but that  
12 might happen some July or August if it is really really hot.

13           And then the last step, just some curiosities of  
14 the Air District rules, even though our plant is able to  
15 start up in 10 minutes, and only the last three minutes of  
16 that are we actually burning fuel, for modeling purposes,  
17 the start-up is traded as a half hour. Well, so peakers  
18 start often twice a day, so there are a lot of starts and  
19 that adds up. And secondly, we take the maximum month which  
20 is July and August, each of which has 31 days, but we have  
21 to divide it by 30 days because that is another rule. Now  
22 we end up with an offset requirement of 555 pounds per day  
23 for, ultimately, actual emissions in the air of about 102.  
24 That gets further exacerbated 30 years from now, 40 years  
25 from now, when we shut down the plant, we would only be able

1 to credit offsets equal to actual operations at actual  
2 capacity factors, which, you know, 30 or 40 years from now,  
3 with technology advancing, might only be half of the 102,  
4 and that of course contributes to the offset shortage.

5 COMMISSIONER BYRON: So are you putting this table  
6 together here -- I mean, it is very informative -- but are  
7 you suggesting that this is something you have to live with?  
8 Or are you suggesting that maybe the Air Board should look  
9 more closely at the details of these rules?

10 MR. KOSTRZEWA: Well, these are the outcomes of  
11 the rules and, under my list of solutions there, you know, I  
12 recognize SB 288 is a high hurdle, but in terms of what  
13 might we hope and dream for, one way to solve part of the  
14 problem would be, if we permit at six pounds per hour, and  
15 when we build the plant we test it at four pounds per hour,  
16 it would be nice to get those excess ERCs back and put them  
17 back into the market. So that would be solution number one.  
18 The second step would be, you know, recognizing plants have  
19 to be able to operate for that 1 in 10 summer, but that  
20 almost never happens. If we could offset for a typical year  
21 and maybe keep some running average from year to year to  
22 make sure that we are not actually over-emitting, that would  
23 also significantly reduce the number of offsets we would  
24 require. Another one would be to offset based on capacity  
25 factor, rather than strictly operating hours. One of the

1 big benefits of the fast start -- or quick start fast brown  
2 peakers is that they will be able to go up and down a lot  
3 because, as a developer of wind and solar, we know wind and  
4 solar go up and down a lot, and gas-fired generation is  
5 going to have to compensate for that. So we will, in a lot  
6 of cases, be operating at low loads, at minimum load, so  
7 that we can pick up in the event a cloud passes over or the  
8 wind slows down. And even though we might operate 20  
9 percent of the hours, we probably will not operate at 20  
10 percent capacity factor, for example. A lot of times, the  
11 plant will be running just for ancillary services. Of  
12 course, one of the obvious ones, the biggest impact, is  
13 really going from the average month to the maximum month, if  
14 that could be changed, that would be just great. And some  
15 of those curious aspects of the rules that artificially  
16 extend the start duration, or assuming that the maximum  
17 month has 30 days instead of 31, you know, could save us a  
18 few more -- it is not a lot, but it is still a few percent.

19 VICE CHAIR BOYD: A question if I might.

20 MR. KOSTRZEWA: Of course.

21 VICE CHAIR BOYD: Your proposal to offset for  
22 typical year, not 1 in 10, what happens when the 1 in 10  
23 shows up? Are you going to have a bank of credits stashed  
24 away of your own that you could dip in to use? Or do you  
25 have some other suggestion for how that deficiency in that

1 year is addressed?

2 MR. KOSTRZEWA: Well, it is not a very well formed  
3 proposal, but I believe that we could keep track from year  
4 to year of our operating hours. And if the limit was not a  
5 number of hours per month, or a number of hours per year,  
6 but operating hours over a sliding five-year window, for  
7 example, I think we could reduce the volume quite a bit.

8 VICE CHAIR BOYD: Thanks.

9 MR. KOSTRZEWA: Another thing we deal with as  
10 developers, if there are not enough on the market, you know,  
11 can we create offsets? And one of the barriers to that is,  
12 again, the way some of the rules are designed. The chart on  
13 the left does not mean much in terms of actual numbers, but  
14 there is an emissions source that we have been talking to  
15 that emits, say, at 100 percent, is their current emissions,  
16 and by applying some additional control technologies, we  
17 could reduce their emissions down to that little bitty  
18 remaining part. And so the air cleans up by that whole  
19 amount that is shown as emission reduction, but under the  
20 Air District's rules, the amount of offsets we can actually  
21 create is first discounted by assuming that the source  
22 should go down to best available control technology, and the  
23 only emission reduction credits that can actually be  
24 certified are those, to the extent that best available  
25 control technology is exceeded. The problem is the

1 certifiable amount becomes very very small, and the cost of  
2 the controls spread over the whole volume actually would  
3 work, but the cost of the emission control is spread over  
4 that tiny amount that is actually certifiable is prohibitive  
5 in most cases, and results in a missed opportunity to clean  
6 the air and contribute towards solving the offset problem.  
7 Solutions there, obviously, take another look at those rules  
8 to facilitate ERC creation.

9           Another potential solution is for the Air District  
10 and the CEC to certify a power plant on the condition that,  
11 before we start construction, we must deliver ERCs. That  
12 would allow us to get through the permitting process and be  
13 ready to go with obviously a huge hurdle ahead of us, but  
14 would have projects ready to go, but for either creating or  
15 obtaining ERCs, and then, although not related to this  
16 chart, another solution would be to allow new generators to  
17 opt into the SO<sub>x</sub> reclaim program. Right now, we are required  
18 to provide SO<sub>x</sub> ERCs which are also in short supply. Electric  
19 utilities are allowed to opt into the SO<sub>x</sub> reclaim program,  
20 but really independent power generators are the major source  
21 of new generation, and you know, if one were to really take  
22 the position that IPP plants are now serving that need,  
23 particularly if you are contracted with that utility, that  
24 would solve that problem, or at least address that problem.

25           And lastly, also related to ERC creation, the Air



1 District has really done an amazing job over the last, well,  
2 20 years at least, in eliminating stationary source  
3 emissions, particularly squeezing down the electricity  
4 generation sector. Those charts there are from the AQMD's  
5 2007 Air Quality Management Plan, and those are pie charts  
6 showing where the PM-10 and PM-2.5 emissions in the Air  
7 Basin are coming from, and as you can see, electricity  
8 generation is only a tiny sliver there. It makes it very  
9 hard, well, and if you look at other stationary sources  
10 there, those are also tiny slivers. In order to really be  
11 able to create new emission offsets, we are going to have to  
12 be able to access non-traditional sources like area sources  
13 and mobile sources, which is a problem because,  
14 particularly, the mobile sources have a shorter lifetime  
15 than electricity generation facilities do. But one  
16 possibility is to over-control and clean up the air a whole  
17 bunch up front, and equivalent to what the emissions would  
18 be with the life of the power plant. And that is all I have  
19 got.

20 COMMISSIONER BYRON: Well, very good. And a lot  
21 of new material, some helpful ideas. Any response from  
22 anyone or questions?

23 MR. VAWTER: Don Vawter with AES Southland. I  
24 would just like to make a couple of comments about Mr.  
25 Kostrzewa's assertion that we would, through the Rule 1304

1 exemption, be in a position to exert market power at the  
2 expense of the ratepayers. First of all, I would support  
3 most, if not all, of Larry's proposed fixes to ease the  
4 pressure on the ARC market, and would be glad to then bid  
5 against his proposed project in an open RFO. The Brownfield  
6 project is always going to have a cost advantage over a  
7 Greenfield project, and we have no problem demonstrating  
8 that through an RFO. Secondly, there are many ways to  
9 ensure that a power plant developer is providing a fair and  
10 adequate price. There are reams of public data about what  
11 it costs to build site and operate generation, third party  
12 engineering studies could be done to verify that. I think  
13 it is an overblown concern, frankly. There is also, through  
14 AB 1576, which passed into law a few years ago, the  
15 opportunity for utilities to get full rate recovery by  
16 negotiating repowers of OTC units that, on an open book  
17 negotiation basis, and we would be willing to do that.  
18 Thank you.

19 COMMISSIONER BYRON: Mr. Nazemi, I wonder if you  
20 -- and I do not mean to put you on the spot, but some of  
21 these that are offered as solutions, and I would  
22 characterize them more as suggestions on Mr. Kostrzewa's  
23 slide 5 with regard to how to recalculate more -- let's say  
24 discreetly calculate the emission credits. Do any of these  
25 make sense? I guess the question that I have is, are the

1 responses to each of these, not that you should have to  
2 provide them now, as to why the Air Board calculates this  
3 the way it does --

4 MR. NAZEMI: -- power plant, for example, actually  
5 these are not only in our rules and regulations, but they  
6 are also requirements under the federal law that, in order  
7 for an emission reduction to be valid, it has to be real.  
8 And you cannot say that the facility was permitted to emit  
9 this many emissions, therefore, when they shut down, they  
10 should get all of those as credits; you have to show that  
11 they were real. So that is why we look at a past number of  
12 years of operation and calculate how much emissions they  
13 have. Contrary, for a new power plant, federal law requires  
14 the emissions to be offset at its potential to emit level.  
15 So, again, that is a requirement that we have to follow.  
16 Now, there are certain specific language in our New Source  
17 Review Regulations that directs us how to calculate the  
18 emissions, you know, look at the 30-day average for a  
19 maximum month, actually the language in our rules requires  
20 us to do that. The slide that Larry put on the screen that  
21 these are some ideas, they are in fact ideas that we are  
22 looking at, but as I indicated earlier, almost all of those  
23 ideas required a rule change, and once we do a rule  
24 amendment, we need to adhere to Senate Bill 288. So it does  
25 have some issues associated with it, not that they are

1 impossible, but it is not just a staff position that we are  
2 doing it this way, because we like to, it is the requirement  
3 in our rule.

4           COMMISSIONER BYRON: Good. Thank you, Mr.  
5 Kostrzewa, but I think in the interest of time, I am going  
6 to ask that we move on. We could spend a great deal more  
7 time talking about some of the material you presented us,  
8 and I appreciate it very much. I believe Mr. Carroll is  
9 next, from Latham & Watkins.

10           MR. CARROLL: Good afternoon. I am Mike Carroll  
11 with Latham & Watkins, and just by way of introduction, I  
12 guess it probably is apparent by virtue of the panel that I  
13 am appearing on, but just in the interest of full  
14 disclosure, I do represent many of the CEC jurisdictional  
15 projects proposed in the South Coast that have been affected  
16 by these issues, in addition to many many non-CEC  
17 jurisdictional projects that were affected by some of the  
18 collateral impacts associated with the litigation  
19 surrounding these issues. And we also represent all of the  
20 private parties that are party to both the state court and  
21 the federal court litigation.

22           One of the benefits, I suppose, or the problems,  
23 depending on how you look at it, following so many good  
24 presenters on a topic is that many of the issues that I had  
25 intended to cover have been covered already. So, in some

1 cases, I will move through my slides relatively quickly.  
2 There is a lot of information here, and I know we are  
3 running a little bit behind, as I said, because some of this  
4 has been covered, I will try to move quickly through a  
5 number of these slides.

6 COMMISSIONER BYRON: Thank you. I appreciate it,  
7 but I do want you to make sure you feel free to cover your  
8 points adequately.

9 MR. CARROLL: I appreciate it. I will do that. I  
10 think an important point that I want to make is to debunk  
11 what I think has been a myth that has been created  
12 surrounding this set of issues that, what we are faced here  
13 is with a choice between having adequate electric  
14 reliability to meet the needs of our citizenry, and to  
15 maintain a stable economy, and protecting the environment.  
16 And quite to the contrary, we think that the proposals for a  
17 new gas-fired generation in the South Coast District  
18 accomplishes both of those objectives, or all of those  
19 objectives, and that we really do not have a trade-off here  
20 between electric reliability and environmental protection.

21 As has been seen in many of the presentations that  
22 have been made already, we think that there really is a need  
23 to develop new gas-fired generation in order to meet the  
24 electric reliability needs in Southern California. The  
25 extent to which you believe that need exists varies and we

1 have seen different presentations, depending on what  
2 assumptions you put into your analysis, or into your model,  
3 you will come out with a different number. But I think  
4 that, regardless of which analysis you look at, it is clear  
5 that there is a need and I think we need to be cautious, and  
6 there has been some recognition and discussion of this today  
7 about the assumptions that are made because, assuming that  
8 we need X Megawatts of gas-fired generation, or assuming  
9 that we need X Megawatts of renewables, or assuming that we  
10 need a certain amount of transmission and moving forward,  
11 assuming that we therefore have a plan, can be very  
12 dangerous because, as those of us -- and I include the  
13 Commissioners in this -- that are involved in the siting of  
14 these projects know, saying that you need X Megawatts and  
15 getting X Megawatts approved and on the ground and operating  
16 are two very different things. So I think we need to be  
17 very cautious about the assumptions that we make in these  
18 models.

19           The other thing that I would say, with all due  
20 respect to all the engineers in the room, is that sometimes  
21 the analyses or the models have a degree of logic in them  
22 that have no place in environmental regulatory realms, and  
23 so, while we can all sit and say that it makes sense that  
24 you should offset your emissions based on what you think  
25 your emissions will be, or that you should be allowed to

1 generate credits based on what your emissions reductions  
2 are, as we have seen from Mr. Kostrzewa's presentation, the  
3 rules do not always work that way. And so we always need to  
4 factor in the somewhat artificial and somewhat illogical  
5 constraints that we sometimes have with respect to the  
6 regulations.

7           Again, what I have done here is really summarize  
8 much of the analysis that has been presented to date. There  
9 are a number of quotes here, firm reports prepared by  
10 entities that have spoken today, and I am not going to read  
11 them, you can do those now, or do those later to the extent  
12 that you do not have time now. But they really pull  
13 together what, for me, were the bottom line conclusions of  
14 some of these analyses. It is clear that without the  
15 ability to develop new generation in the South Coast, we are  
16 running head long into the Rule 1630B requirements for once-  
17 through cooling, and that we are not going to be able to  
18 address that problem in its entirety through transmission.

19           It is also clear that the state has recognized  
20 that because of that constraint and others, that the  
21 potential for not being able to meet the needs of the  
22 Southern California Region is a very real potential, and  
23 that is a high risk issue that the state needs to pay  
24 immediate attention to, and that the consequences of failing  
25 to pay attention to that issue are very significant to our

1 economy and that the repercussions of not being able to  
2 supply the electricity demand in the Southern California  
3 region could be devastating to the economy at a point in  
4 time where we obviously can least afford actual disruptions  
5 to the economy or, frankly, even the threat of a disruption  
6 or a great uncertainty associated with a threat of a  
7 disruption.

8           And setting aside the economic consequences of the  
9 inability to meet demands for electricity are all the  
10 secondary environmental impacts that go along with those,  
11 and I do not have any bullet points here, but what we saw in  
12 the 2001-2002 timeframe, I am sure that the district would  
13 back me up on this, is that when we are unable to meet the  
14 demands of the region from the grid, what we see are  
15 secondary back-up sources of generation coming online,  
16 diesel-fired emergency generators and other similar sources,  
17 with really dramatically higher impacts and public health  
18 issues associated with those back-up sources of generation.  
19 So the failure to address this issue and meet the demand,  
20 and ensure that we have adequate supply to meet that demand  
21 is not just an economic issue, but becomes a very real  
22 environmental and public health issue, also.

23           As I said, meeting those needs from an electrical  
24 reliability standpoint is not at the expense of  
25 environmental protection. When we look at the sources who



1 have pointed out the need for new generation to meet the  
2 electric reliability needs, what we also see is that those  
3 very same sources are pointed at the need for new generation  
4 to meet the environmental needs. So you see some of the  
5 same conclusions and the same quotes here that support the  
6 need for new generation for reliability supporting the need  
7 for new generation to meet the once-through cooling  
8 requirement amongst other environmental regulations.

9           We have identified, or the California Energy  
10 Commission has identified very specifically a number of  
11 plants that will not be able to be taken offline as hoped,  
12 or as planned, in the event that new infrastructure does not  
13 become available. We, as developers and proposers of new  
14 projects, are frequently asked, "Well, if your project comes  
15 online, which one will come off?" That is a very difficult  
16 question to answer for a lot of reasons that I do not have  
17 time to get into today, but it is a difficult question to  
18 answer. A much easier question to answer, frankly, is if we  
19 do not come online, these are the projects that will not  
20 come offline. And we are very capable of identifying what  
21 those projects are, and here are a handful of them.

22           With respect to the air emissions, and we spent a  
23 lot of time talking about the once-through cooling issue  
24 today, but obviously the new plants come online with state-  
25 of-the-art emission control technology, and on a per

1 Megawatt basis, are much cleaner in terms of all the  
2 criteria pollutants that are listed here, than in the  
3 existing generation. And, of course, as I said, we have  
4 covered the water quality issues I think pretty adequately  
5 today.

6 Another advantage from an environmental  
7 perspective of bringing the new generation online is the  
8 support for the intermittent renewable sources. And, again,  
9 this is a point that has been touched on. The natural gas-  
10 fired generation firms up the intermittent renewables, and  
11 in addition, it frees up transmission to import renewable  
12 energy, which almost exclusively comes from outside of the  
13 South Coast Basin. So if we have any hope of meeting our  
14 goals with respect to renewables, we really need the gas-  
15 fired generation to back that up. There has also been a lot  
16 of discussion today about the ancillary services. Here are  
17 some quotes on that particular issue from the Energy  
18 Commission, and the need to consider in the analysis the  
19 ancillary services provided by the natural gas-fired  
20 generations. And I think Mr. Turner and others made very  
21 good points to this effect, that we cannot analyze any  
22 single piece of this puzzle to the exclusion of others, but  
23 really need to take into consideration all the various  
24 aspects of the puzzle in order to find out effective  
25 solutions, and the ancillary services are certainly a part

1 of that.

2           Moving on to the state's greenhouse gas reduction  
3 goals, and obviously this is very much tied to the support  
4 that the gas-fired plants provide for the renewables, this  
5 particular graphic, I am sure, is difficult to read from the  
6 back of the room, as is the one here, but the points that  
7 are made by the two graphics are really those that are made  
8 in the bullet points here, which is that the addition of the  
9 new gas-fired plants are necessary in order to support and  
10 back-up the renewable generation, and that if we hope to  
11 achieve the greenhouse gas targets, we are going to need to  
12 move to a greater reliance on renewable energy, and we can  
13 only do that if we have got natural gas-fired plants there  
14 to back it up when that inherently intermittent renewable  
15 energy is not available. And then, finally, the addition of  
16 the new gas-fired plants improves the overall efficiency of  
17 the electric system. Again, I think that is a point that we  
18 have hit on repeatedly today. I do not know that we have  
19 really talked too much about it in the context of meeting  
20 our greenhouse gas reduction targets, but the ability to  
21 support and have a reliable electric system that is heavily  
22 reliant on renewables, which is what we are going to have to  
23 have to meet the greenhouse gas reductions, is obviously  
24 very dependent on having the natural gas-fired plants to  
25 back that up.

1           So just in summary, and I will not read through  
2 these, but our view is that this is not a trade-off, that it  
3 is sort of a -- not sort of -- it is a classic win-win  
4 situation where these new natural gas-fired projects not  
5 only allow us to meet the reliability and the electrical  
6 needs of the region, but also are critical to advancing the  
7 environmental objectives of the region.

8           So what is standing in our way of implementing  
9 what I view as a classic win-win? In large part, but  
10 certainly not exclusively, because as we all know, there are  
11 many many issues that affect these projects, you know, this  
12 is just one, and sometimes I think we lose sight of it, and  
13 it is a critical issue, but developers that are faced with  
14 these projects face hundreds or thousands of regulatory  
15 requirements, many of which are very thorny. The emission  
16 offset issue is a couple of lines in the Clean Air Act, it  
17 is one of thousands of requirements that need to be dealt  
18 with in connection with siting these plants, but it is a  
19 very important one. As has been discussed, the emission  
20 offset requirement comes from the New Source Review Program  
21 embodied in federal, state and local law, which has three  
22 major components, the requirement to install best available  
23 control technology, the requirement to do emissions modeling  
24 to demonstrate that you will not exceed or contribute to an  
25 exceedance of an air quality standard, and the one that we

1 are talking about today, the emission offset requirement. I  
2 think it is important to keep in mind that the New Source  
3 Review offset requirement is a mandatory requirement, and I  
4 think frequently there is confusion between this requirement  
5 and "market-based" or "market incentives" programs, or  
6 economic incentives programs, that are put in place to  
7 provide flexibility for compliance. So, for example, there  
8 are programs out there, which we think frequently make a lot  
9 of sense, that will allow a facility to avoid installing  
10 controls, provided they obtain a marketable emission  
11 reduction credit from another facility. That really is a  
12 compliance flexibility mechanism, it is a way to achieve the  
13 environmental objective at a lower cost. That is not what  
14 the New Source Review offset requirement is. The New Source  
15 Review offset requirement is a mandatory requirement that  
16 you need to comply with on top of everything else. So you  
17 are not getting out of anything, the ability to buy credits  
18 from other sources is not some sort of an economic incentive  
19 or an economic break, it is a mandatory requirement, so it  
20 is very different, for example, from the reclaim program in  
21 the South Coast, which really is intended to be a compliance  
22 flexibility program.

23           The current offset markets, at least with respect  
24 to some pollutants in the South Coast, are dysfunctional.  
25 The supply is diminishing. The reason for that is that the

1 traditional sources of supply has been the shutdown of  
2 existing facilities, or the over-control of existing  
3 facilities. So generally the private market was funded by  
4 credits that came from typically large facilities that shut  
5 their operations down, moved them out of the Southern  
6 California area, or just shut them down completely, and  
7 applied for emission reduction credits based on their  
8 emission reductions. Or, they were based on facilities that  
9 controlled their equipment beyond the level otherwise  
10 required, and then sought emission reduction credits for the  
11 margin between those two. We do not have a lot of big  
12 industry left in Southern California other than that which  
13 is sort of geographically tied because it is tied to  
14 infrastructure that cannot be easily moved or it is tied to  
15 being on the Coast, but things that could move out of the  
16 South Coast, for the most part, have. You know, the auto  
17 industry is a good example, furniture manufacturing is  
18 another. So we have gotten to a point where you do not have  
19 a lot of sources shutting down in Southern California in any  
20 given year, and therefore there are not many opportunities  
21 to generate credits. The businesses that are there have  
22 been very heavily regulated, so the ability to go above and  
23 beyond and generate credits through over-compliance, has  
24 also been diminished. And then, finally, as has been  
25 mentioned, the credit generation rules are extremely

1 stringent, and so there is very little relationship between  
2 your actual emission reductions and what you get in the way  
3 of a bankable emission reduction credit. At the same time,  
4 while the supply has been diminishing, the demand has been  
5 steady with spikes. Existing facilities do need to  
6 modernize, they do need to upgrade, they do need to put in  
7 new equipment from time to time, and that generates a  
8 demand, a rather steady demand, for emission reduction  
9 credits, and every once in a while we have a spike, like in  
10 2001-2002, and 2005-2006, where we have a slug of power  
11 plants, for example, coming through. So the demand  
12 continues to grow while the supply has diminished. And, as  
13 I said, the problem does vary pollutant by pollutant with  
14 PM-10 and SO<sub>x</sub> being the most serious problem right now.

15 In terms of possible solutions, Mr. Kostrzewa  
16 mentioned some of these. We need new credit generation  
17 programs, and we need to look certainly outside of the  
18 electric generating sector, and outside of the stationary  
19 source sector, in order to find new credit generation  
20 opportunities. The opportunities for emission reductions,  
21 if you look at the pie chart from Mr. Kostrzewa's  
22 presentation, are from the mobile sector. So we need to  
23 develop more programs to generate credits from the mobile  
24 sector, and that includes on-road and off-road fugitive  
25 dust, and we have had some projects permitted based on road

1 paving generation of credits, the South Coast began to  
2 undertake an effort to go down that path that, frankly, has  
3 been stalled. We would like to see that re-started. But  
4 certainly, the mobile sector, whether it be tailpipe  
5 emissions or emissions associated with fugitive dust, needs  
6 to be tapped into to generate additional credits. We need  
7 more rationale offset requirements and very sympathetic to  
8 what was not said, staff does not impose the requirements  
9 because they want to, or they think it is a good idea, they  
10 are right that that is what the regulations require, but we  
11 need to look at those regulations and make amendments where  
12 appropriate. And staff is also right that we need to take  
13 state law considerations, specifically SB 288, but I do not  
14 think we can just sort of throw up our hands and say, well,  
15 it requires a rule amendment, and we have to deal with SB  
16 288, so that is the end of the analysis. I think we need to  
17 undertake those difficult efforts if SB 288 is a problem,  
18 then make SB 288 needs to be addressed. And as we have seen  
19 in the recent legislative session, the Legislature is  
20 willing to step up when necessary to address problems like  
21 this. And so I think it is very important that we focus on  
22 imposing some more rationality into some of these  
23 requirements in terms of determining the amount of emission  
24 offsets necessary for a project. We need greater  
25 flexibility from the staffs at all agencies, frankly,



1 including the California Energy Commission, to be creative  
2 in the way we come up with emission offsets. We have used,  
3 and continue to use, such things as intra-district and  
4 inter-Basin offsets, that is typically a very complicated  
5 and difficult process, it needs to be made a little bit less  
6 complicated and a little bit less difficult. We have also  
7 used inter-pollutant offsets. We think that these are very  
8 viable mechanisms and we would like to see more receptivity  
9 on the part of the staffs of all the agencies to these  
10 creative proposals.

11           And finally, we think the District's internal  
12 emission offset accounts are a valuable and viable source of  
13 emission offsets. We have heard that recent legislation has  
14 been passed that will allow the District again to tap into  
15 that for certain types of projects, unfortunately not CEC  
16 jurisdictional projects, but we have also heard that AB 1318  
17 was also passed by the Legislature, which will allow the  
18 District to tap into those offset accounts for at least one  
19 CEC jurisdictional project, and then hopefully we will see  
20 some legislation in the next session that will expand that  
21 to two other projects. So we continue to believe that that  
22 is a very viable source of offsets. They should not be  
23 focused on to the exclusion of everything above it, but it  
24 should continue to be on the list.

25           And then, finally, something that I just want to

1 touch on, I really will not get into it, is reconsideration  
2 of whether the emission offset requirement really makes any  
3 sense anymore, given the situation in California.

4 COMMISSIONER BYRON: Mr. Carroll, if I may  
5 interrupt, please, with a question. And you may have  
6 described this already and I am just missing it with regard  
7 to the terminology because I am not an emission credit  
8 reduction expert. But Mr. Kostrzewa's last point in his  
9 last slide was the rule -- if I may just read it -- "Rule  
10 changes needed to allow stationary sources to use ERCs from  
11 other sources." Is that described in your list, as well?

12 MR. CARROLL: Yes.

13 COMMISSIONER BYRON: It is? Which one is --

14 MR. CARROLL: That would be the New Credit  
15 Generation Programs from the mobile sector, I think, is what  
16 Mr. Kostrzewa was referring to primarily.

17 COMMISSIONER BYRON: All right, thank you.

18 MR. CARROLL: There has been a lot of discussion  
19 about the District's internal emission offset account. I  
20 have highlighted that as one of the items from my list  
21 because it is one of the primary topics for discussion  
22 today. I think it is important to recognize that that is a  
23 very long standing source of emission offsets in Southern  
24 California. Use of those offsets to permit projects did not  
25 just arise in 2006 or 2007, it goes back many many years in

1 the District, with the approval of all of the oversight  
2 agencies, including the California Air Resources Board and  
3 the U.S. Environmental Protection Agency permitted many many  
4 sources pursuant to Rule 1309.1 and Rule 1304, using  
5 emission offsets from its Internal Emission Offset Accounts.  
6 Those offset accounts have been determined by all of the  
7 agencies, including South Coast, the Air Resources Board,  
8 the USEPA, and the California Energy Commission, which has  
9 approved many projects in reliance on emission offsets from  
10 the District's Internal Emission Accounts. Those programs  
11 have been determined to be compliant with all the applicable  
12 requirements that apply to emission offsets by all of those  
13 regulatory agencies. We have not had any adverse court  
14 rulings that go to the validity of the offsets in the  
15 District's Internal Emission Offset Accounts, so we had an  
16 adverse court ruling in state court, but I think it is  
17 important to keep in mind that that was a CEQA lawsuit, and  
18 what the judge said was that the District failed to comply  
19 with the California Environmental Quality Act when it  
20 adopted the rule to make offsets available to power plants.  
21 It did not get into whether or not the offsets in the  
22 district's internal accounts applied with state law, or  
23 federal law, certainly. It was a CEQA lawsuit. By the same  
24 token, we have pending federal litigation. That litigation  
25 has been dismissed on jurisdictional grounds and no ruling

1 has been rendered at the federal level regarding the  
2 validity of the offsets in the district's internal accounts.  
3 So, as I said, all of the agencies with regulatory over-  
4 sight over those emission offsetting accounts have deemed  
5 them to be compliant with state and federal law, and no  
6 court ruling at the state or federal level has said anything  
7 to the contrary. And as I indicated in my comments from the  
8 podium, there has been a lot of speculation about what EPA  
9 thinks of the District's internal accounts. I think they  
10 have been very clear what they think about the District's  
11 internal accounts.

12           The other point that I think is very important to  
13 remember about the use of the District's internal accounts  
14 are the mitigation fees. And we have not talked too much  
15 about those, but when a source buys credits from another  
16 private party, the private party gets that money and puts it  
17 in their pockets. And I am not opposed to private parties  
18 making money or making a profit, I mean, that is the way our  
19 system works, but one of the tremendous advantages  
20 associated with a source going to the AQMD to obtain its  
21 emission offsets is that the mitigation fees that would  
22 otherwise go to a private party go to the agency, and that  
23 are expended in the communities where the project is going  
24 to be located on an emission reduction project. So you are  
25 really getting a twofer, if you will, when the credits come

1 from the agency. You are getting the reductions that are  
2 behind those credits in the first place, and then you are  
3 getting additional reductions on top of that, that can be  
4 generated with the TARP funds.

5           And I also want to put to rest this notion that  
6 those credits are made available at a discount, somehow.  
7 You know, we saw a presentation earlier where Mr. Nazemi  
8 said that there have been trades at the \$350,000 a pound  
9 range. That gets translated into, well, if you let a pound  
10 go for anything less than \$350,000, you know, that is a deep  
11 discount, or that is a give away to the power sector.  
12 Nothing could be further from the truth. Those are  
13 aberrational prices that are a function of a completely  
14 dysfunctional market. When the 1990 amendments to the Clean  
15 Air Act were adopted, the maximum cost that was projected  
16 for compliance with those requirements, including these  
17 offset requirements, was \$25,000 a ton. We are not spending  
18 \$350,000 a pound, so clearly something has gotten completely  
19 out of whack. The fact that somebody who was absolutely  
20 desperate to move forward with a project and needed a pound,  
21 was willing to go out and spend \$350,000 does not mean that  
22 that is the market price that should therefore be applied to  
23 a power plant that needs 200 pounds to move forward. So I  
24 think that is a very important point to keep in mind when we  
25 are looking at the pricing.

1           This really is reflective of things that we have  
2 talked about today, again, I did not know how much of the  
3 background we would get into when I put together this  
4 presentation, but obviously there was rulemaking in 2006 and  
5 2007 to make offsets available to the power sector that  
6 involved an amendment of Rule 1309.1 and the adoption of the  
7 tracking -- we have talked about Rule 1315. That  
8 precipitated state court litigation, again, a CEQA case  
9 filed in August of 2007, decided in July of 2008, with a  
10 writ issued in -- that should be November 3<sup>rd</sup> of 2008, that  
11 is a typo, not 2005 -- which set aside the rulemaking and  
12 set aside any actions that had been taken pursuant thereto.  
13 As has also been mentioned, that writ was modified just  
14 recently in September of this year to allow the District to  
15 permit sources pursuant to essential public services  
16 pursuant to 1309.1, and 1304, exempt sources -- the District  
17 has some views about whether that writ really provides the  
18 flexibility that they need to do that. We understand their  
19 point of view on that. The state court litigation is  
20 currently on appeal.

21           And then we have federal litigation filed in  
22 August of 2008. This is a Clean Air Act citizen suit  
23 brought by essentially the same group of petitioners that  
24 alleged that the offsets failed to meet the requirements of  
25 Clean Air Act section 173. As I mentioned, that case was

1 dismissed on jurisdictional grounds in July of this year.  
2 We are waiting for a final judgment to be entered on that  
3 decision.

4           It has also been discussed, there was a  
5 legislative response, SB 827, which is sort of the broad  
6 scoped rule which reinstates the rule 1304 exemptions, and  
7 the ability of the district to permit essential public  
8 services pursuant to 1309.1. It allows the district to fund  
9 its internal emission offset account so that it can do that.  
10 That is the provision that the district believes is critical  
11 in the legislation that is not present in the Judge's  
12 modification of the writ. It does not make offsets  
13 generally available to CEC jurisdictional projects, so there  
14 were previous iterations of SB 827, and before it became SB  
15 827, it was SB 696, which would have allowed the District to  
16 make credits generally available to CEC jurisdictional  
17 projects, but the final bill did not provide for that.

18           And it has also been discussed, AB 1318 was also  
19 passed, and that is a project that would allow the district  
20 to make offsets available from its internal accounts to  
21 certain qualifying CEC jurisdictional projects. The CPD  
22 Sentinel project is the only project that has been proposed  
23 that meets the qualification criteria pursuant to 1318.  
24 Again, we do not have time to get into this. I think there  
25 is a real question about whether or not the emission offset

1 requirement makes any sense anymore. In my view, it has  
2 become counterproductive from an environmental perspective  
3 because, if you cannot get offsets to build new things,  
4 whether it is a power plant or an oil refinery, or a boiler,  
5 what do you do? You just keep operating the old thing. And  
6 so we do not get upgrades, we do not get the advantage of  
7 new technology, so in my view, the emission offset  
8 requirement has really become obsolete. This is something  
9 that requires, obviously, legislative fixes at both the  
10 state and the federal level in order to address, and is  
11 certainly beyond the scope of our discussion today.

12           Implications for CEC jurisdictional projects --  
13 and this is really the wrap-up. I think it is certainly  
14 true that we need new natural gas-fired generation to meet  
15 both reliability needs of the region, and to achieve our  
16 environmental objectives. It is also absolutely true that,  
17 notwithstanding recent developments in the Legislature, that  
18 the emission offsets remain an impediment to achieving those  
19 goals. We think multiple solutions will be required, and a  
20 lot of them have been put on the table today - more rational  
21 offset requirements, additional offset generation programs,  
22 more flexibility in the way that the offset requirements are  
23 implemented, and support for AB 1318 and future legislative  
24 initiatives. We do not think that any of these require  
25 environmental compromise. We think all these solutions can



1 be implemented with adequate protections for the  
2 environment. And we think that everybody needs to  
3 participate in these, and I certainly understand the  
4 frustration that the District feels, they stepped out in a  
5 very significant way, have got a lot of litigation and a lot  
6 of grief for their efforts, but, frankly, they are part of  
7 the problem whether they like it or not, the Air Resources  
8 Board is part of the problem, when it comes to SB 288, the  
9 Legislature continues to be -- I should not say "part of the  
10 problem" -- part of the solution. I think all of the  
11 agencies need to be part of the solution here and none of  
12 them can wash their hands of this, we really need everybody  
13 at the table as we have today in order to move this forward.  
14 So with that, I will conclude, and thank you very much for  
15 allowing me to be here today.

16 COMMISSIONER BYRON: Mr. Carroll, very good. Were  
17 there questions or comments?

18 MR. MARTINEZ: I just have a quick question and --

19 COMMISSIONER BYRON: Please identify yourself.

20 MR. MARTINEZ: I am Adrian Martinez from the  
21 Natural Resources Defense Council.

22 COMMISSIONER BYRON: Thank you.

23 MR. MARTINEZ: I guess my question -- are you  
24 encouraging the CEC to promote amendments to SB 288 and  
25 amendments to the Federal Clean Air Act? Is that the

1 suggestions at the end of the presentation?

2 MR. CARROLL: I do not think anything should be  
3 off the table at this point. I think that the emission  
4 offset situation, and, you know, we have been very focused  
5 on South Coast, but let me tell you, this is coming all up  
6 and down the state, and we are already seeing it in other  
7 areas where we are coming to the point where we cannot  
8 permit anything, no matter how environmentally beneficial,  
9 because of the emission offset requirement. And so I think  
10 everything should be on the table. I am not necessarily  
11 encouraging anybody to do anything today, other than look at  
12 all the options and reach their own independent conclusions  
13 about what options they think they should pursue.

14 MR. MARTINEZ: Thanks, that is helpful.

15 COMMISSIONER BYRON: Dr. Jaske.

16 DR. JASKE: I just have one clarifying question.  
17 In this slide, but perhaps more so than in the previous  
18 slide, you -- yes, that one -- well, in any event, you are  
19 using a very special kind of jargon -- CEC jurisdictional  
20 projects. What is your thinking about the South Coast 1304  
21 exemption for repowers and whether those are CEC  
22 jurisdictional projects?

23 MR. CARROLL: Well, I think some of those are CEC  
24 jurisdictional projects, some of them are not, you know,  
25 depending on whether or not they otherwise meet the

1 requirement to be within the jurisdiction of the CEC. So I  
2 do not think the emission offset issue has any bearing on  
3 whether or not they are CEC jurisdictional. 1304 exemptions  
4 would be available for some CEC jurisdictional projects;  
5 there are other projects that could qualify for 1304  
6 exemptions that would not. So I do not know if that answers  
7 your question or not.

8 COMMISSIONER BYRON: Dr. Jaske, would you please  
9 come back up and answer this question. What would be non-  
10 jurisdictional for the CEC in the South Coast? What would  
11 be a non-jurisdictional repower?

12 DR. JASKE: I believe there is a portion of the  
13 Public Resources Code that establishes a constraint on our  
14 jurisdiction over a power plant, no matter how big it is,  
15 that if it is not more than 50 Megawatts larger than the  
16 prime mover being replaced, that it is -- that we do not  
17 have jurisdiction, it is some county or city in which it is  
18 located. And so, to the extent that 1304 becomes the path  
19 that is available to generators, by generators choosing not  
20 to have a net increase above 50 Megawatts, they have a  
21 completely different permitting process, and one that does  
22 not evidently involve the Energy Commission.

23 COMMISSIONER BYRON: Right, for instance, the  
24 Scattergood at 803 Megawatts could go to 852 Megawatts and  
25 not be jurisdictional?

1 DR. JASKE: That is correct.

2 COMMISSIONER BYRON: So -- go ahead, Mr. Carroll.

3 MR. CARROLL: I will also point out, and we have  
4 been very focused on the repowering provision in 1304, there  
5 are other exemptions in Rule 1304, including an exemption  
6 for resource recovery projects. We have many many energy  
7 projects that are not subject to the CEC jurisdictional  
8 landfill gas projects, municipal solid waste energy  
9 projects, that have been bogged down as a result of this  
10 litigation, that would also be able to move forward under  
11 1304.

12 COMMISSIONER BYRON: Mr. Carroll, thank you. Very  
13 good.

14 MR. CARROLL: Thank you.

15 COMMISSIONER BYRON: And I apologize, we could go  
16 on with further discussion, but we have still many  
17 presentations to go. And we are behind schedule for a panel  
18 discussion. I believe Mr. Sciortino from the City of  
19 Anaheim is the last of our presenters.

20 MR. SCIORTINO: Thank you, Commissioner. I find  
21 myself in an unusual position of being last on the agenda,  
22 typically Anaheim enjoys the alphabetical advantage of going  
23 first. I want to thank the Commissioners for the  
24 opportunity to talk about our canyon project today. Thanks  
25 for the invitation to speak. I was going to talk a bit

1 about our experience with our whole process. I want to  
2 caveat my comments in that Anaheim -- this canyon project is  
3 the first project we built in 20 years, so while the  
4 licensing process is very familiar to everybody in the  
5 audience, you will have to forgive us in terms of our  
6 inexperience with the process, and maybe some naive  
7 expectations on my own part, and it will probably be  
8 blatantly obvious in my presentation.

9           Our needs for the canyon project are, currently,  
10 we have about 500 Megawatts of resource capability on our  
11 system, some of these are jointly owned projects with some  
12 of the other cities in the Southern California Region. Most  
13 of that is a 24-hour must take base load capacity, so we  
14 really have a peaking requirement. During the summer, we  
15 peak between 550 and 590, so we have a deficiency of about  
16 50 to 90 Megawatts, depending on how hot it is. In addition  
17 to that, we have a planning reserve margin, a resource  
18 adequacy margin, that we must maintain, so that is going to  
19 ask for an additional 80-100 Megawatts.

20           There is another issue there that I know we have  
21 talked about, the local capacity requirement that was  
22 discussed earlier, that the ISO has for the Basin. The load  
23 serving entities such as Anaheim and some of the other  
24 cities have to share that obligation. Currently, we have a  
25 need for 300 Megawatts of LCR requirements. Most of our

1 generation is outside the state, so we have very little in  
2 terms of local capacity requirements. So this one of the  
3 bigger reasons for why we needed the facility. In addition,  
4 we do have some wind and hydro facility renewables that we  
5 are part project participants in, so having a quick start  
6 capability was another reason for our needs. Just briefly,  
7 it is a 200 Megawatt facility to 4 LM 6000 simple cycle  
8 facilities. We actually have designed for a NO<sub>x</sub> target of  
9 2.3, it is a little bit lower than the current 2.5, and we  
10 are also using reclaimed water for our operational needs.

11 I just wanted to kind of walk you through what our  
12 experience has been to date. When we first filed our  
13 application, we based it on the 1309.1 section in terms of  
14 how to calculate what ERCs we actually needed. We went  
15 through a process of determining that, based on the rules  
16 that Mohsen talked about earlier, that we probably need  
17 about 500 hours of operations, that translated to about 48  
18 pounds per day for ERCs. Based on the rules at the time,  
19 the cost for the ERCs were about \$92,000 per ton. We would  
20 have written the check for about \$5 million, which would  
21 have gone to the AQMD to help them find other programs for  
22 remediation. We filed our application in December of 2007.  
23 Now, here is where my naivety comes into play, we had every  
24 expectation that, not that we were presuming the license was  
25 a fete accompli, we just thought that it was a pretty

1 standard program, pretty standard generation, we thought  
2 based on our best knowledge and backing into how long the  
3 process would take, that we would actually have the project  
4 commercially operational summer of 2010, those were our  
5 expectations. So when the Judge's Order came out to -- in  
6 July that we talked about earlier -- we had to scramble to  
7 figure out, okay, well, we might not be able to rely on  
8 1309.1, we had meetings with the AQMD to talk about, well,  
9 what possible solutions do we have for this. We did a  
10 little bit of research. Now, I know that we talked earlier  
11 about Section 1304 for repowering, my understanding is that  
12 there was another provision within this, that if you were  
13 emitting less than four tons, you could file under that  
14 application, or that rule, and you would be exempt from  
15 having to require the ERCs. So based on that information,  
16 we sort of backed into, well, if you could not emit more  
17 than four tons a year, what would your operational level  
18 have to be to be able to qualify for 1304? So we went  
19 through quite a bit of revising our application, which took  
20 some time for us to do. And so we had to file a revised  
21 application to the AQMD in September of '08, so we had to  
22 completely alter a lot of the tables that go into the  
23 application, so we thought we were good for that. Then,  
24 when the clarification order came out in November, that  
25 excluded our ability to qualify even under 1304, so our only

1 solution at this point, bearing in mind all along that we  
2 wanted to stay on schedule, or keep the project moving  
3 along, as opposed to waiting for clarification of how this  
4 was all going to play out, we entered into the market to  
5 procure the ERCs directly. Now, just based on our own  
6 experience, I did want to say that, while Mohsen's graph  
7 showed there were 1,000 ERCs available, our experience was  
8 that, well, you have got two markets there, you have got one  
9 for the inland area, and then you have one for the coastal  
10 -- we were in the coastal market. So we worked feverishly  
11 with trying to get the credits, only to find that the  
12 actuality was, when we entered the market to actually buy  
13 the credits, there was only one provider, one seller, who  
14 had enough credits for us to purchase to get back on  
15 schedule. Now, that is not 1,000 Megawatts that was on the  
16 table, just to let you know anecdotally, the first shot was  
17 that this seller had, I think, about 28 pounds available and  
18 we needed 48. So we procured those, we had with one seller  
19 and I think, obvious to him, that he knew what we were  
20 doing, we ended up paying \$310,000 a pound for that, rather  
21 than the \$92 that we would have gotten under the old  
22 provision. So we really did not have any negotiation  
23 capability in terms of the price. You have got one seller  
24 providing something, you know, if you walk into a car dealer  
25 and there is only one car there, and you really needed to



1 drive it, then you really do not have much leverage in terms  
2 of discussing price. And considering that we needed to  
3 continue our process going, we ended up having to procure  
4 it, and the other 20 became available at a later time. But  
5 the bottom line is we ended spending about \$15.5 million for  
6 the credits. Now, to a lot of you, that may not sound like  
7 a lot of money, but for the City, you know, our revenue  
8 requirement is \$270 million a year, so an extra \$10 million  
9 added to the project, I had a hard time going up to the 11<sup>th</sup>  
10 floor to explain that to my boss, but we still wanted to  
11 make sure that the project floated and continued on. So  
12 then, based on the 48, that sort of gives you an indication  
13 of what we calculated to come up with the 48 that we needed,  
14 so we were back to operating over 4,000 hours.

15           So the final application we submitted, it was  
16 almost a year later from the initial application because we  
17 had to go back once again to revise all the tables that go  
18 into the application the AQMD needs to do their work. So  
19 anyway, just to give you kind of from our perspective how  
20 this whole thing plays out, as I said, our original  
21 application was filed in December, we got data adequacy in  
22 three months, the AQMD, because of the delay in the process,  
23 we actually ended up getting our PVOC in February of '09, so  
24 this whole litigation process actually cost Anaheim at least  
25 six months in terms of revising its application and being

1 able to stay on schedule. We had a joint workshop in May of  
2 '09. I forgot to mention, when the Energy Commission issues  
3 its preliminary staff assessment -- and I have the second  
4 column in there as sort of the theoretical timeline that is  
5 provided and, again, this is our inexperience with the  
6 process by actually believing that those dates would  
7 actually occur. Most of you have probably had more  
8 experience with licensing processes and understand that  
9 there is always, you know, the optimal versus what actually  
10 happens. So we were still trying to stay on schedule with  
11 the process. So as we kind of go down the table, we are at  
12 a point right now where we are still waiting for the Energy  
13 Commission's Final Staff Assessment, that would be the last  
14 regulatory piece that would get us into the licensing  
15 process. We are hopeful that the October date that we were  
16 given is going to work. And I think, based on that scenario  
17 of trying to get back on schedule, when we went through this  
18 process of the delays of getting the actual ERCs, it became  
19 very clear that the summer of 2010 was highly ambitious, so  
20 we were hoping that the summer of '11 would work. Anaheim  
21 definitely needs to have the capacity available. At this  
22 point, I am not quite sure if we are going to be able to  
23 make the summer, depending upon, you know, if there are  
24 further delays. We have kind of walked through starting  
25 with construction and working ourselves backwards where

1 different dates had to fall in play for us to stay to that  
2 schedule.

3           So this is just Anaheim's unique experience that  
4 occurred. So my apologies to Mohsen, he has already  
5 addressed this several times, but obviously I put my  
6 presentation together in advance of knowing what he was  
7 going to say. But I understand the rules. We were  
8 suggesting, and I guess this has already been commented on,  
9 for a peaking facility, I guess the rules are the rules, but  
10 I think our recommendations fall in line with what some of  
11 the other speakers were saying. We ended up buying  
12 theoretically for the entire 4,300 hours. Our practical use  
13 for the facility during a 20-year forecast was closer to  
14 2,000 in terms of what we would actually operate, but  
15 because of the way the rules are set up, we definitely ended  
16 up having to procure what would effectively play out to  
17 4,300. So our recommendation, obviously, is in line with  
18 what some of the other folks have brought up. If we had a  
19 magic wand to wave the rules, what would make sense? For a  
20 peaking facility, some of the experiences here that we  
21 thought out were, you know, you have a limitation for how  
22 many hours during the month that you get permitted for, and  
23 I understand that is our number that we put in there, so  
24 what we are thinking is would it make more sense for a  
25 peaker to look at it on an annual perspective, rather than

1 the worst month scenario. And the reason for that,  
2 obviously, is during the non-summer months, there is really  
3 not a need to run a peaking facility, at least from our  
4 perspective, because we have so much base load capacity, we  
5 have more than we need for nine months out of the year. So  
6 we thought, well, if you had the ability to calculate this  
7 on an annual basis, it gives you a couple of advantages.  
8 One is, if you could actually bank those for the entire  
9 year, so that in any give month, if you need to use more  
10 operating hours to be able to meet your load for extenuating  
11 circumstances, is essentially it would be, well, I do not  
12 need to run them in March, how about if I have those  
13 concentrated in the summer months? So that was some of our  
14 thinking.

15           The other thing we thought of for a multiple  
16 facility, multiple unit facility, each one of the ERC  
17 credits is based on a per turbine, and we were wondering  
18 would it help if you applied it for the entire facility.  
19 And the thought process was, well, supposing that you ran  
20 one turbine for 90 hours that you were limited to for the  
21 month, and now you have to go to another turbine in order to  
22 meet your load, and what happens if that turbine breaks and  
23 is unavailable? It just precludes you from being able to  
24 rely on a different turbine. So we thought that if you  
25 looked at it from a facility basis versus a per turbine

1 basis, and if you looked at it from across the entire year,  
2 for peaking facilities, it might help in that it would give  
3 the operator a little bit more flexibility. But  
4 notwithstanding the rules, that was just our proposal.

5           Just to wrap things up really quick, I had a  
6 couple of questions, and this is again based on our  
7 inexperience with the process. We were not quite sure what  
8 the rationale for the 1.2 multiplier was after you go  
9 through the process of calculating how many hours you are  
10 going to operate. The other questions we had were, in terms  
11 of this particular process, do you need to demonstrate  
12 having secured your credits so early in the process? That  
13 is kind of an investment that, if you are not going to be  
14 able to do anything other than buying out at the market,  
15 that is kind of an investment that you have to make way  
16 early in the process. And, of course, without those, I  
17 think -- my understanding was the PDOC is not issuing until  
18 you procure those, and that is another meter that starts the  
19 process.

20           And then, finally, recognizing where I am in my  
21 venue here, as far as the licensing process is, and this is  
22 again our inexperience with the process, we were trying to  
23 go backwards with where we thought we needed the project to  
24 be online, and we were somewhat relying on the Energy  
25 Commission's website to say, well, this is how much time it

1 takes to do this, this is how much time to get to this  
2 point. Our process was that, you know, I do not know if  
3 this is the case for other developers, you know, we had to  
4 have a contract with GE for the turbines. We had to procure  
5 those in advance because part of the requirements for the  
6 PDOC is you have to have a vendor guarantee for the  
7 emissions, and a vendor is not going to give you that until  
8 you sign a contract. So that was one of our dilemmas, was  
9 that all right, we have already got the turbines, they are  
10 already being built. The other process for cities is that a  
11 lot of things that we do are driven by putting out requests  
12 for proposals to take bids for construction. Those have to  
13 be done in advance and they have to be done under a City  
14 procurement rule. So we have actually hired EPC contractors  
15 in anticipation that we would be available to go commercial  
16 in '11, and, again, Commissioner, I am not trying to  
17 preclude the process, or presume that the license is a fete  
18 accompli, but basically the question is a rhetorical one,  
19 you know, how do utilities have to plan for how far in  
20 advance they need to do things in order to go through the  
21 process? So it was more of a rhetorical question, not a  
22 criticism, just our experience has kind of got us to the  
23 point where we are just holding several people at bay  
24 waiting for the process to continue, recognizing that we had  
25 to do that in order to stay the schedule.

1           COMMISSIONER BYRON: Well, it is very informative,  
2 Mr. Sciortino, and I assure you, we will be making our  
3 decision based upon the evidentiary record, not what you  
4 present here today.

5           MR. SCIORTINO: Of course.

6           COMMISSIONER BYRON: So this is very helpful. And  
7 your questions, I do not know, Commissioner, how many  
8 developers should we let come up and underscore for Mr.  
9 Sciortino that it is actually worse than he thinks?

10          VICE CHAIR BOYD: I was not going to say anything  
11 like that. And I was going to try to make him feel better,  
12 though, that he is not alone.

13          COMMISSIONER BYRON: Yes --

14          VICE CHAIR BOYD: My own notes say, you know, good  
15 points -- when is the last time we looked at the whole  
16 system rather than our piece of it?

17          COMMISSIONER BYRON: Yeah.

18          MR. SCIORTINO: That is just our experience, sir.  
19 I just wanted to just kind of tell you how it happened for  
20 us, that it is unfortunate that we were right in the middle  
21 of the perfect storm with the lawsuit and that is probably  
22 the main drive for us to figure out, well, what we needed to  
23 do to kind of figure out, well, where do we get the credits?  
24 And I just want to reiterate, the market is not really out  
25 there, at least at the time we went to actually get

1 something that made sense.

2 COMMISSIONER BYRON: I suspect there are many here  
3 that could tell you they are also involved in this perfect  
4 storm, and could underscore some of the same observations  
5 that you had. I do not want to preclude them from speaking,  
6 but if it is alright with you, in the interest of time, I am  
7 going to suggest that we press on.

8 MR. SCIORTINO: Of course.

9 COMMISSIONER BYRON: Thank you very much for your  
10 comments. In fact, I think you are on our next panel, as  
11 well. And if I could ask, it looks as though we have got  
12 three of the Energy Commission staff moderating this, Dr.  
13 Jaske, Mr. Layton, and Mr. Vidaver. And the panelists, I  
14 think, are you going to have them all come forward to the  
15 table? All right, let's do this as quickly as we can, then,  
16 so we can get to the content and I will allow my moderators  
17 to do the introductions. And we have some new panelists who  
18 have not spoken today, but if you would all just come  
19 forward and grab a seat? Do you have nametags there, too?  
20 Is that right? Dr. Jaske, how do you plan to conduct your  
21 panel?

22 DR. JASKE: We are --

23 COMMISSIONER BYRON: Go ahead and speak to the  
24 panelists. I do not want you to have to turn towards me.

25 DR. JASKE: I think we are going to go through the



1 questions. We may decide to pare down some of the questions  
2 because they are -- they have been covered sufficiently, and  
3 like we have in some other workshops along this topic, we  
4 may point to a particular person to lead off, and then ask  
5 the other panelists to sort of react to that opening  
6 comment.

7 MR. VIDAVER: Do we need the panelists introduced  
8 at this point? Or do we all sort of know who we are by now?

9 COMMISSIONER BYRON: No, I think that would be  
10 great. Please, you can introduce them, or have them go  
11 around.

12 MR. CARROLL: Mike Carroll with Latham & Watkins.

13 MR. KOSTRZEWA: Larry Kostrzewa, Edison Mission  
14 Energy.

15 MR. SCIORTINO: Steve Sciortino, City of Anaheim.

16 MR. NAZEMI: Mohsen Nazemi, South Coast.

17 MR. MINICK: Mark Minick, Southern California  
18 Edison.

19 MR. JOHNSON: Keith Johnson, California ISO.

20 MR. MOORE: Bruce Moore, LA Department of Water  
21 and Power.

22 MR. VIDAVER: The first question in the panel  
23 topics that are appended to the agenda deals with South  
24 Coast rules being based on worst month scenarios, and asks  
25 for a comparison of the rules with those in other districts,

1 and alternatives suggested by parties. Parties have  
2 suggested numerous alternatives in the past couple of hours  
3 and, in the interest of saving time, perhaps we can  
4 stipulate that, if parties want to comment on anything they  
5 heard, speak to anything that they have not heard suggested  
6 in the last couple of hours, they may do so in written  
7 comments, unless anyone would like to take on Mr. Nazemi  
8 again right now. So if you have comments on the  
9 presentations that you have seen, and the recommendations  
10 for rule revision, etc., please provide them in written  
11 comments, and any additional recommendations you may have,  
12 etc. And then we will probably at some point turn them over  
13 to Mr. Nazemi and talk to him about them, and you will get  
14 the chance to read our summary some time in December of  
15 January, before we officially release the document. Do you  
16 want to do this in rotation? Or do you want me to --

17 DR. JASKE: Well, I think that the Question 2 has  
18 obviously been provoked by the whole discussion today and  
19 Mr. Nazemi said it well, that the district is now looking to  
20 the state to figure out how to somehow or other pull  
21 together something that serves the function of 1309.1 for  
22 new power plants. So maybe one question is, and ever since  
23 the State Court first decision was issued in July, there has  
24 been all kinds of discussions about this issue, so the  
25 question is, is there a forum that already exists, that can

1 take on this issue? Or is there something new that needs to  
2 be formed to really bring focus to it? So perhaps, Mr.  
3 Nazemi, if you could answer that question and others react  
4 to that?

5 MR. NAZEMI: Sure. I think from South Coast's  
6 perspective, the forum should consist of the agencies that  
7 have the expertise in dealing with the issues, such as the  
8 energy demand forecasts, transmission line capability, local  
9 reliability. Again, you heard a lot about inertia and other  
10 factors that are unique to the utility industry, and  
11 agencies that have jurisdiction over there, so I think you  
12 are really asking whether there are the experts available to  
13 do this, and the answer is yes; whether there is a forum  
14 that is an official forum, I guess I cannot say that I am  
15 aware of one. But I think the expertise relies on it, the  
16 Energy Commission relies on it, and the System Operators,  
17 the utilities, the Public Utilities Commissions, the agency  
18 that approves these contracts, so they all have their own  
19 unique expertise and they are all part of this equation.  
20 But South Coast clearly is -- our expertise is in air  
21 quality and not in transmission line and renewable resources  
22 and things like that, so I do not think it would be fair for  
23 us to carry this load. I think it would be appropriate that  
24 other agencies who are the experts do it, and if they need  
25 help from us relative to air quality, we will be more than

1 happy to participate.

2 MR. SCIORTINO: Dr. Jaske, doesn't the Energy  
3 Commission have a working paper that talks about gas-fired  
4 generation for the state required due to a variety of  
5 reasons? One is operational, some of it is in support of  
6 the renewables that have to come in play, and I think that  
7 was a joint effort. As an outside contractor, I think that  
8 should be brought in to help you with that. But I think it  
9 has been, in terms of working with the ISO and some other  
10 folks that have some input into it, I kind of thought that  
11 that was a nice starting point, by identifying, well, what  
12 is the potential for gas generation required? And I think,  
13 if I understood that study, they were looking at it in a  
14 more microcosm perspective like, okay, well, let's look at  
15 it in terms of SP-15 requirements, and break it down in more  
16 granularity. But, to me, it seemed like, well, that is a  
17 very good place to start from because it identifies a lot of  
18 the issues that we talked about this morning for regulating,  
19 for intermittent resources, and where it needed to be built,  
20 and I thought, well, if you could just take that document  
21 and carry it a step forward and identify, "Well, how would  
22 these guys actually operate under that scenario?" You could  
23 actually calculate, well, how many emissions would be  
24 required based on that? I guess my concern is that, you  
25 know, if you have any kind of an allocation process, it is

1 sort of like the first guys that get to the trough actually  
2 will get the ERC credits in the future, but what do you do  
3 for folks five years from now who need to develop something?  
4 So I thought that document that the Energy Commission has  
5 sponsored was a very good working -- a very good place to  
6 start.

7 DR. JASKE: Well, I think maybe it is a start, but  
8 as Mr. Minick and other representatives of the ISO said,  
9 there is probably a long ways to go to really wrap it all  
10 together and have it be sufficiently tight, that everyone  
11 could buy into it. Other reaction?

12 MR. CARROLL: I would just say I would caution  
13 against getting too bogged down in finding out exactly how  
14 many Megawatts we need before we proceed to figure out what  
15 the solutions for the emission offset problems are because I  
16 do not think we need to know the former with an extremely  
17 high level of precision in order to recognize that we have  
18 got a problem. So we do not know exactly how many Megawatts  
19 we need, perhaps, but we know that we need some, and at this  
20 point, with a couple of limited exceptions, we cannot permit  
21 any. So I get a little bit nervous that we are going to get  
22 too bogged down in refining the model, and come to some  
23 conclusion on exactly how many Megawatts we need, and then  
24 once we have got that behind us, then we will turn to, okay,  
25 then how many offsets do we need and how are we going to

1 generate those. I do not think we need to take these issues  
2 in sequence. I think they are both important, but I think  
3 we can move forward on the emission offset solution in  
4 parallel with the planning that is underway. And to some  
5 extent, you know, there is this what I view as sort of an  
6 irrational concern about, you know, over-building, or having  
7 too many offsets available in the market that, you know, if  
8 we make offsets available, then we will have all these power  
9 plants built that we will not need, and they will just  
10 operate all the time and emit whether there is demand for  
11 the electricity or not. Well, you know, the extent to which  
12 the power plants operate is the extent to which there is  
13 demand for the electricity, and the more -- so if there is  
14 no demand for the electricity, then the plants will not run.  
15 And if we [quote unquote] "build too many" new power plants,  
16 you know, the worst thing that happens is more and more of  
17 the old power plants get displaced. So this concern that we  
18 have seen on the part of a number of decision makers about,  
19 you know, "If you make too many offsets available, we are  
20 going to have an over-built situation, and that is bad." I  
21 frankly do not understand that. And so I would just say  
22 let's get focused on the emission offset problem and  
23 solutions to that problem while, at the same time, you know,  
24 doing the planning work that you all undertake to determine  
25 what the future needs of the area are.

1           MR. VIDAVER: Do you see there being some -- do we  
2 have a priority reserve mechanism that might set a number of  
3 offsets, but would be made available? Or do you see  
4 something along the lines of long-term contracts for  
5 resources being authorized by, for example, the CPUC, and  
6 whatever was awarded in that contract would be given a  
7 number of offsets that it needed? Or, you mentioned  
8 something about a market solution to this and I am trying to  
9 -- what picture do you have in your mind of how offsets are  
10 made available, aside from the numerous revisions you  
11 suggested?

12           MR. CARROLL: Well, I do not think you need to  
13 have -- and, in fact, I do not think it is a good idea to  
14 have a single source of offsets. You know, I think that we  
15 should look to ways to make the private market more robust.  
16 I think it should be not so onerous for private parties to  
17 generate offsets and make those available in the private  
18 market. I think we need to tap into the South Coast  
19 Internal Emission Offset Accounts, notwithstanding some  
20 current hesitancy that they might have to delve back into  
21 that for the power sector. I think we need to because that  
22 is a viable pool of offsets that should be made available to  
23 the power sector, beyond what current rules and legislation  
24 will allow. So, you know, like any market, having a sole  
25 source situation is not good. And so I think we need to

1 look at a variety of opportunities and markets, whether they  
2 be agency-based, or private markets, so that we have got  
3 various opportunities for these sources to satisfy their  
4 emission offset requirements.

5 MR. KOSTRZEWA: I would recommend not tying it to  
6 what he is saying, a power contract or not. You know, in  
7 the current market that we have for power in Southern  
8 California, or in California, it does not make sense to  
9 build a power plant without a power contract, but it is the  
10 goal of many policy makers to create a robust competitive  
11 market like you have in PJM, where utilities do not have to  
12 sign long term power contracts in order to get facilities  
13 built, that really the market determines what is the right  
14 thing to do. And we should not develop a mechanism for how  
15 things are today because how things are today are  
16 transitional. And I definitely want to emphasize what Mike  
17 said about how much power plants operate. We cannot force  
18 electricity into the grid that the grid will not use, and so  
19 new power plants, well, the most competitive power plants  
20 are the ones that run. And if non-competitive power plants  
21 cannot compete, then they will shut down. It is how things  
22 work in the east, and it has been quite effective at  
23 bringing a lot of new generation capacity on throughout PJM.

24 VICE CHAIR BOYD: This forces me to ask a question  
25 of anybody. Since this is [quote] "allegedly an evolving



1 market," do you think that there is a level playing field  
2 now in existence in the California market for the IOUs and  
3 independent power producers, particularly with the recent  
4 advent of so much utility owned generation?

5 MR. KOSTRZEWA: That is a third there. I think  
6 the CEC is -- or maybe it is CAISO that puts out a study  
7 every year that shows their calculation of whether new  
8 generation could afford to build in the market as it exists.  
9 And the energy market certainly does not support  
10 constructing any new generation, and nor does it in the  
11 east, and so, really, it is the resource adequacy market  
12 that provides the famous missing money. And that missing  
13 money really comes from the desire for more reliability than  
14 would be truly economic. And with resource adequacy  
15 payments where they are, there is not enough money to  
16 support the generation. And the caps on those prices may  
17 keep that from happening.

18 MR. CARROLL: I am going to deflect a little bit  
19 your question of whether or not it is a level playing field,  
20 but what I can say is, for the independent power producers,  
21 it is becoming a playing field that is not very attractive  
22 to enter into, and some of this was mentioned by other  
23 speakers, but when you couple the money required to buy the  
24 security emission offsets, as early in the process as the  
25 CEC staff would like you to acquire them, with the money

1 that is required to secure your power purchase agreement  
2 with the utility, with the money that is now required to  
3 secure your electric system upgrades under the new cluster  
4 approach of the ISO, and those are almost three certainties,  
5 and on top of that, if you feel for whatever reason you need  
6 to move forward with your equipment and your EPC contractor,  
7 the amount of money that is required to be laid down very  
8 very early in the process, before we could have any idea as  
9 to whether or not you are going to have a project or not, is  
10 becoming a huge deterrent for the companies that I  
11 represent, and are looking at it and just saying, "This just  
12 doesn't work. We do not have and we cannot get financing of  
13 that magnitude for a project that is so speculative." And  
14 we are talking about all of those obligations coming, you  
15 know, early in the process, certainly pre-PSA. So whether  
16 it is a level playing field or not, it is one that is  
17 becoming very unattractive to the independent power  
18 producers and very difficult, I think, on a going forward  
19 basis for us to attract that sort of investment.

20 VICE CHAIR BOYD: Thank you.

21 DR. JASKE: The last sentence of that question  
22 raises the whole question, assuming that there is some  
23 amount or aggregate amount of offsets, credits that are  
24 available, how they might be allocated is one word, or some  
25 other word, how will multiple power plants end up obtaining

1 some presumably limited amount? Any thoughts from you about  
2 how to deal with that? First come, first served? Or what?

3 MR. KOSTRZEWA: Well, I would say first come,  
4 first served, but maybe that trivializes the complexity and  
5 difficulty and expense that Mike is talking about. It is  
6 very very costly to build a power plant and so it is highly  
7 unlikely that more people will seek to be served than the  
8 market will support. But I think it does make an awful lot  
9 of sense to have a pool of offsets in one place accessible  
10 at a known price, so that in order to create at least a  
11 competitive market of new generation options, I use the era  
12 word, the shovel-ready projects, so that when a utility  
13 seeks new generation capacity through a request for offers,  
14 maybe there are three or four or five projects that are  
15 permitted on the basis that they will have access to this  
16 pool when and if they build. And that way, the utility gets  
17 to choose between power plants that have gone through the  
18 process and are real, but without that 50 to 80, or however  
19 many million dollars speculative up front bet we would have  
20 to get through the permitting process without such a pool.

21 MR. VIDAVER: So it sounds like your solution is  
22 slightly larger than Mr. Carroll's, maybe. You are allowing  
23 for a more administrative socialist solution.

24 MR. KOSTRZEWA: Well, I would like to have a  
25 competitive solution on top of that; I think if it was a lot

1 easier to create emission offsets, we would be out doing  
2 that, and if we could not generate enough offsets on our  
3 own, it would be nice to have the pool to fall back on.

4 MR. SCIORTINO: Dave, can I just ask one question?  
5 And I know this process is targeted more for the investor-  
6 owns, but I am curious to how the developers would perceive  
7 if it was a first come, first served, they would gobble them  
8 all up, and then at some point LADWP or some of the other  
9 cities who do not have that same process, but come along  
10 three years from now, or five years from now, there is no  
11 ERCs to be had, but yet we have the same obligations to  
12 provide the same reliability criteria that the investor owns  
13 do.

14 MR. KOSTRZEWA: Well, as a developer, again, I do  
15 not think that we would be gobbling them up without building  
16 the plants, and if we built the plants, then there would be  
17 plenty of capacity in the market.

18 MR. SCIORTINO: Well, I am just saying that the  
19 first come, first serve, I always get a little bit nervous.  
20 I know when 1309 came out and there was -- I think it was a  
21 limit of 20 -- 2,000 Megawatts, or something to that effect,  
22 and it was like, well, the first 2,000 to come to play, they  
23 get the credits, and then three years from now, Anaheim or  
24 LA comes in and says, "Hey, we have some deficiencies that  
25 we need;" we are not in the same position where we could

1 actually build our own. We do not need to go through the  
2 development process that Edison might have to.

3 MR. KOSTRZEWA: I completely agree that a cap on  
4 the number of Megawatts would be not beneficial.

5 MR. CARROLL: But that cap, it was 2,700  
6 Megawatts, that was not a function of the quantity of  
7 offsets available, that was, again, the concern on the part  
8 of the governing board of South Coast that there would be  
9 too many power plants built if they made an unlimited amount  
10 of offsets available. So that was their attempt to --

11 MR. SCIORTINO: Well, I understand that, but  
12 conceptually what I am getting at is, what if there is a  
13 limit on the number of ERCs that are available for  
14 allocation? And if you go to this first come, first served,  
15 and it is the developers for Edison who has requirements,  
16 then if those allocations are used up -- and that is why I  
17 kind of like this long term planning thing where you are  
18 looking toward the future in terms of, well, what is the  
19 overall over the next 20 years. I know you do not like the  
20 idea, but from a scientific standpoint, you know, it is not  
21 just the investor owns who have facilities in South Coast.  
22 I mean, Edison is not the only player here.

23 MR. CARROLL: Do not get me wrong, I am not saying  
24 that we do not need to undertake the long term planning, I  
25 think we should, but I just do not think we need to wait to

1 find out what the offset solution is until that long term  
2 planning is completed, especially since, you know, what I am  
3 hearing is that is going to take months, if not years, to do  
4 that. And frankly, I think we may be getting a little too  
5 bogged down in an issue that we need not because I think if  
6 we start to implement some of the solutions that have been  
7 proposed, there are going to be plenty of offsets available  
8 for all the projects they can otherwise get permitted and  
9 get financed, and move forward. So I do not -- let's not  
10 get too bogged down in "what are we going to do with this  
11 limited pool of offsets," to the exclusion of thinking  
12 broadly about how do we generate enough offsets for  
13 everybody. Because if you look at those pie charts, there  
14 are a lot of emissions out there, we just need to figure out  
15 how to tap into those to generate credits for stationary  
16 sources.

17 MR. KOSTRZEWA: And, of course, figuring out how  
18 many Megawatts are needed, and that study is obsolete the  
19 day it is printed because the world changes.

20 MR. VIDAVER: Looking at Mr. Nazemi to see how he  
21 is reacting to the notion that a New Source Review Working  
22 Group can come to a consensus and lead the District down a  
23 path to a larger number of offsets without too much  
24 difficulty.

25 MR. NAZEMI: Well, I think I am kind of having

1 like a déjà vu where our governing board was amending our  
2 rules to allow the use of credits from our bank by the power  
3 plants and, in their infinite wisdom, they came up with,  
4 well, has to be a viable project. So one project proponent  
5 can come in and put a huge hold on all the credits that are  
6 in the bank and not allow competitors to move forward, so  
7 the idea of first come, first serve from the point of view  
8 that, you know, the moment you put in your application, you  
9 are the first one in line, was not appealing to us. So we  
10 thought that viability means you have to demonstrate that  
11 you are going through this CEC licensing process, and at  
12 least meet their requirements. It has to demonstrate that  
13 you are either, like the City of Anaheim, or LADWP, that  
14 your local municipality is serving your native load, or if  
15 you are selling into the grid, that you have acquired a  
16 contract that shows that you are serious about providing  
17 this power into the grid for California residents. And the  
18 limitation, as Mr. Carroll indicated, was not a limitation  
19 on the amount of offsets, it was based on, again, at the  
20 time we were relying on the projections that were given by  
21 the state agencies, and they were looking at some 2,500,  
22 maybe 3,000 Megawatts of increased generation that is needed  
23 to prevent rolling blackouts in one in 10 situations, so  
24 that limitation was put on so that, if in fact things  
25 change, and it was determined that, whoa, this was the wrong

1 estimate, we needed really 5,000, that there was a provision  
2 that you can always go back to the governing board and  
3 demonstrate that, you know, there was a need for additional  
4 new generation. So that is the answer to the first part of  
5 the question, you know, how do we go about us doing this.  
6 But, again, we are not in that business anymore, so it is  
7 something that you all need to participate in and decide how  
8 best to do this. As far as suggestions that are being  
9 discussed, and New Source Review changes, again, I caution  
10 that ideas sound very reasonable when you talk about it, but  
11 again, we are dealing with mandates in the federal and state  
12 and local requirements that needs to undergo rulemaking and  
13 I know we have mentioned numerous times today SB 288, and I  
14 am not sure, Commissioners, if you are familiar with what SB  
15 288 is or not, but it was an attempt by State of California  
16 to stop rollbacks of federal administration in terms of New  
17 Source Review when the federal law was being amended, to say  
18 that you cannot make your New Source Review any less  
19 stringent than what it was in effect December of 2002, which  
20 was the day before the federal law went into effect. So any  
21 change that we make to our New Source Review Rules, since SB  
22 288 was passed, needs to undergo scrutiny, to make a  
23 determination that it is not making rules less stringent.  
24 Now, that is not to say we cannot make any changes, but it  
25 is -- I just do not want to leave you with the idea that,



1 you know, again, we are sitting there not moving and making  
2 a change to fix the problem, and if we did that, that would  
3 be the end of it. In fact, one of the plaintiffs actually  
4 filed a petition with the California Air Resources Board  
5 when we did the adoption of Rule 1315, and amendments to  
6 1309.1, that we violated SB 288, and that took ARB a couple  
7 of years before they made a decision that we did not. So I  
8 do not want to lead you on the rosy path that, as soon as  
9 you make a change to New Source Review, everything is fixed.

10 MR. VIDAVER: Thank you. Okay, let's see if we  
11 can get the gentleman from AES leaping out of his chair.  
12 Let's talk about 1304 exemptions. I am not exactly sure  
13 where to start, but there are those who believe that making  
14 1304 exemptions available to owners of existing power  
15 plants, but not providing such easy access to offsets for  
16 Greenfield facilities, has a number of implications, that  
17 perhaps as fundamentally exist are downright unfair, might  
18 limit competition in RFOs, there is -- that it really would  
19 not matter anyway because Brownfield sites have such an  
20 inherent advantage over Greenfield sites that they do not  
21 really need the additional advantage of a 1304 exemption. I  
22 do not really know where to start and I am sort of tempted  
23 to go back to Mr. Nazemi and ask if there is the  
24 difficulties in a mechanism where the offsets associated  
25 with a Brownfield site would somehow be released from the

1 site itself and allocated sort of in some administrative  
2 sense to the people eligible for a contract, or whatever  
3 requirements you had for eligibility for priority reserve.  
4 Could 1304 -- the offsets under 1304 exemptions somehow be  
5 channeled through that process and not create too many  
6 problems?

7 MR. NAZEMI: Mr. Vidaver, I think it would help if  
8 I just mention that 1304 exemption is not just for power  
9 plants. Power plants is a very small portion of 1304  
10 exemptions. And 1304 was not a provision in our rules that  
11 started with power plants. There may be a few, three or  
12 four different types of exemptions under 1304, but in  
13 general the power plant exemption that comes under 1304 was  
14 in our view an environmentally beneficial exemption. Again,  
15 you are taking an old utility boiler, replacing it with  
16 combined cycle, or advanced technology gas turbine. It did  
17 not take a rocket scientist to typically calculate that the  
18 emissions are going to go down because of the increased  
19 efficiency and the better technology for controlling  
20 emissions on these types of operations. There does not seem  
21 to be -- and then the other process that has been and still  
22 is available under our rules is that any industry, not just  
23 power plants, that needs to build new Greenfield or  
24 Brownfield facilities, that they need to comply with the  
25 offsets requirement and the ability to obtain the credits in

1 the market is a challenge, it is not just for power plants.  
2 As we saw during the moratorium, every facility -- a  
3 hospital had to pay millions of dollars to get offsets, so  
4 if you can imagine there are industries that are not exempt  
5 under 1304 or 1309.1 today, and they have to deal with the  
6 offset issue. What becomes unique for power plants is,  
7 because they typically are a large source of combustion of  
8 natural gas, which is a clean fuel technically speaking, and  
9 when you look at the emissions of the stack, I mean, we  
10 pushed emission limits down to 2 ppm or less for pollutants,  
11 almost to the point where it is hard to measure with  
12 existing instruments, it is not that they are dirty per  
13 pound of or cubic foot of gas that they burn, it is just  
14 that because of the magnitude of the amount of power that  
15 they need to generate, they burn a lot of gas and that  
16 results in a lot of emissions. Now, we are not a proponent  
17 of power plants, but when we look at the alternatives, the  
18 distributed generation was mentioned today by Commissioners  
19 and other parties here, when you look at what the emission  
20 impacts are from distributed generation versus central power  
21 generation, I think unless you are talking about fuel cell  
22 or some very clean micro-turbines, you can easily see that  
23 the emissions are three or four times higher per megawatt,  
24 again of NO<sub>x</sub> that is generated from distributed generation,  
25 that is typically known as internal combustion engine, even

1 with the best controls they can put on it compared to a  
2 power plant. So I think that it needs to be put in  
3 perspective, that is part of what our permitting process  
4 does, we look at what is BACT and what is layer, and those  
5 achievable emission rates and best available control  
6 technology, and would we implement it in that fashion. So  
7 the problem with the power plant that can be unique was that  
8 there was not enough in the open market that they could buy,  
9 and because they needed large chunks of credits, as you  
10 heard from the City of Anaheim, you know, there is not  
11 really many single holders that have that many credits in  
12 their position. So unless you can work out through the  
13 brokers and buy two pounds here and 10 pounds there, and  
14 five pounds over there, and get it all from those that are  
15 willing to sell, then you cannot get it. So I think the  
16 power plants brought this offset issue to maybe more high a  
17 tension, but it is -- the process is there, you generate  
18 ERCs and you sell it in the market to anybody that wants to  
19 use it. I think to some extent we are getting to a point  
20 where, when you are paying \$350,000 per pound per hour of  
21 PM-10, you would have to take a step back and see was that  
22 really the intent of the Clean Air Act and Congress that you  
23 really, instead of putting your money into the technology,  
24 and if you look at a plant, at a 500 Megawatt plant that  
25 spends maybe \$15-20 million on air pollution control

1 technology, if they spend \$200 or \$150 million on offsets,  
2 wouldn't that money be better spent somewhere else? And  
3 those are part of the reasons why we felt that it was -- if  
4 the power was needed, it was appropriate to use the credits  
5 that we have, provided we can charge the power plants and  
6 use that money to invest in emission reductions, which is  
7 ultimately our goal, to clean the air. I do not know if  
8 that gave an answer to your question. That is part of the  
9 thought process.

10 MR. VIDAVER: I am trying to imagine if you have a  
11 power plant that needs 600 pounds of ERCs and those are not  
12 available in the market, so you establish you have a  
13 Brownfield site that has -- that is entitled to those 600  
14 pounds under 1304, and you have another -- an Edison Mission  
15 plant that either has to go into the market where it cannot  
16 get the credits because they are just simply not available,  
17 so the alternative is some kind of District bank that is set  
18 up and methods are devised to allocate that, and you turn  
19 that over to Mr. Kostrzewa, if there is a mechanism by which  
20 the plant that he builds is designed to replace an existing  
21 steam turbine, that then would shut down because the Edison  
22 Mission plant has been given a contract, or has otherwise  
23 been designated as replacing the existing facility, that  
24 sounds like kind of a desirable outcome.

25 MR. NAZEMI: It is from a regional standpoint,

1 but, again, you know, we are talking about what is required  
2 under existing federal, state and local laws. And new  
3 facilities such as the one that Mission Energies is  
4 proposing to build is not at the same location as a facility  
5 that may be in AES' site. So we are looking at a brand new  
6 facility that meets the offsets emissions, you are looking  
7 at an existing facility that is ultimately shutting down a  
8 generating credits, so you need to follow the rules that are  
9 in the books. Unless you want to change those rules, and it  
10 is a smooth process without litigation and anything else,  
11 you are stuck with what is available today. And I do not  
12 think that there is -- I do not think that is the ultimate  
13 solution because, if you think about it, you are asking one  
14 company who cannot get credits out in the open market from  
15 maybe 20 holders who are not willing to sell their credits,  
16 to now go to a single credit holder, and if you think that  
17 single credit holder is going to give a really good deal to  
18 this company, I think you are maybe having a high optimistic  
19 view of this.

20 MR. VIDAVER: I thought I was setting up the  
21 District as being the single credit holder, maybe that was  
22 not -- maybe I am not making myself perfectly clear.

23 MR. NAZEMI: Well, we -- I think there are  
24 companies such as AES, or any other company who has  
25 equipment that are permitted and eventually may shut down,

1 that have the right to at this time come to the District and  
2 claim those credits for their own. We only have credits in  
3 our bank that are what we call "orphan shutdowns" that the  
4 companies who have those equipment and they do not claim  
5 them. So if you are talking about making those credits  
6 available, again, we are kind of like going back in a  
7 circle. We tried to do that, but it did not work.

8 MR. KOSTRZEWA: Personally, I think the electric  
9 utility steam boiler exemption replacement exemption  
10 probably dates to when the electric utilities owned the  
11 steam boilers. And for municipal utilities and for LADWP,  
12 it still makes a lot of sense because the benefit of that  
13 exemption flows directly to the ratepayers. Now that a good  
14 number of the electric utility steam boilers are not owned  
15 by electric utilities, it definitely skews the marketplace,  
16 and you know, maybe when the emission offsets were a few  
17 hundred or a few thousand dollars a pound, that was not a  
18 big issue. But now that offsets can exceed 10 percent of  
19 the cost of building the power plant, those with free  
20 offsets are definitely in a different competitive position  
21 than those that have to buy them, or create them. And I  
22 find it interesting, as was pointed out earlier, of the four  
23 power contracts that SCE signed in their solicitations, only  
24 one of them was from a repowering facility. And, you know,  
25 if we tilt that competitive marketplace, do those

1 competitive options, those competitive options would just  
2 probably disappear. I do not know what the solution is from  
3 that, I certainly would not want to deprive any of the  
4 existing plant owners of their property rights, which, as  
5 Mohsen says, they are entitled to shut down credits. And  
6 there is no way that if one of my plants wins a power  
7 contract that somebody can force somebody else, another  
8 company, to shut down. That just would not be  
9 Constitutional. So I am not sure how we solve that. But a  
10 level playing field would be very nice.

11 MR. VIDAVER: Thank you.

12 COMMISSIONER BYRON: Are we going to hear from any  
13 of those folks on the other side of the podium?

14 DR. JASKE: Yeah, I think I am going to do that  
15 right now and shift us to a portion of Question 4, and that  
16 is the whole notion of squeezing more capacity into limited  
17 air credits by use limited power plants. We talked a good  
18 bit with the example of Mr. Sciortino's Anaheim plant about,  
19 you know, how many hours he was being passed pay-for through  
20 ERCs versus how much he expected that plant to run, but  
21 there is a whole different perspective which is the ISO's  
22 Resource Adequacy process, you know, backstopped by PUC  
23 decisions that is sort of pushing in the completely opposite  
24 direction, wanting more plants to be, in effect, 8,760  
25 available around the clock. So perhaps Mr. Johnson, I would



1 ask that you reflect on ISO's perspective about, you know,  
2 is a future with a lot of use limited power plants where the  
3 ISO wants us to go?

4 MR. JOHNSON: Thanks, Mike. Well, a few comments.  
5 You know, the ISO it being charged with operating the grid  
6 essentially, we are charged with taking the resources that  
7 are procured through the Resource Adequacy Program, and that  
8 is what we operate the system with. So obviously, we would  
9 prefer that we had plants available 24/7, you know, base  
10 load type plants, or at least plants that are available in  
11 the sense that they are physically available and capable of  
12 operating 365 days a year. Of course, that is not the case.  
13 We have a variety of different resources that the ISO uses  
14 to operate the grid. As you all probably know, if you look  
15 at a load duration curve, you know, one might argue that,  
16 given the shape of the curve, that there is really only a  
17 certain number of hours that we really need this peaking  
18 facility, you know, the peaking ability to generate on-peak.  
19 One of the real challenges for the ISO, though, is that we  
20 do not know exactly when that peak is going to occur, and  
21 then, from the operator's perspective, throughout the year  
22 at any give time, there will be either clearances that are  
23 required, or outages, for example -- forced outages. So it  
24 is really a challenge to try to operate the grid with a lot  
25 of use limited resources, with limited numbers of hours that

1 they can run. We are currently doing that. We do have a  
2 number of use limited resources in the fleet now. And so  
3 that is something we have learned to adapt to. I guess  
4 another comment I would have about the resource adequacy  
5 program, the way it is constructed, particularly the piece  
6 from the CPUC, they have this concept of what they call  
7 Resource Adequacy categories, and they are essentially four  
8 buckets. And if you are load serving entity, and you have a  
9 portfolio that you have to fill out for RA, the PUC's  
10 counting rules only allow a certain percentage of the  
11 resources to be of the bearing types. Really what it is  
12 trying to do is to try to mimic that load duration curve.  
13 So, for example, the fourth category is Category 4, it is  
14 really resources that can run 365 days a year. In your  
15 portfolio, you could comprise that 100 percent of those. As  
16 it moves up the steps, three, two and one, there are  
17 resources that are not capable of running that many hours.  
18 So, for example, at the highest level, so-called Category 1,  
19 if you have a resource that you want to have qualified as a  
20 Resource Adequacy resource, it needs to run a combined total  
21 of 210 hours per year through the months of May through  
22 September. So what I am getting at is, and I know one of  
23 the questions in looking at the materials for this workshop  
24 was, would the RA program -- does it put any parameters, if  
25 you will, around what we might need to be cognizant of, and

1 we are thinking about having a lot more resources be use  
2 limited or limited run time. And I think the answer is yes,  
3 to some extent. Some of the load serving entities might  
4 find themselves having difficulty making portfolios that  
5 have a sufficient mix of these category 1, 2, 3, and 4  
6 resources, because you cannot submit an RA showing that it  
7 is composed entirely of Category 1 resources -- remember,  
8 those are the ones with very limited run hours -- you have  
9 to have a mix, at the very least, you could have all number  
10 4, but you certainly cannot have it all use limited. And so  
11 I hope that helps you at least understand kind of how the RA  
12 program works, and how the use limitation, in effect, is  
13 working within the RA Program. One other thing that Mike  
14 has mentioned, that I just mentioned about availability, the  
15 8,760 hours, we do have a new aspect that we have just  
16 implemented in our market called the Standard Capacity  
17 Product. We have crafted a notion of what we call  
18 availability. This is really physical availability of  
19 plants, in other words, what it measures is our resources on  
20 forced outages, and if they are, how does that compare with  
21 the fleet of resources. And what we do is we look at the  
22 last three years of historical performance of resources and  
23 we look at their forced outage rate, and that establishes a  
24 standard. And so, for example, use limited resources have  
25 an ability -- what we do to look at those is, we look at

1 each month there is a standard each month and we make an  
2 allowance for use limited resources such that, if they have  
3 at least fulfilled their commitment during the month, in  
4 other words, they have run for a certain number of hours,  
5 provided a certain amount of Megawatt hours of energy, we  
6 consider that they are [quote unquote] "100 percent  
7 available." So I guess where I am going with this  
8 discussion is to share with you that we certainly would like  
9 resources to be physically available 8,760 hours a year, we  
10 recognize that there are forced outages, so that is not held  
11 against resources from an RA perspective, or an availability  
12 perspective, and then we also recognize that there are  
13 resources that do not run or cannot run for 8,760, and the  
14 program does not penalize them for their legitimate use  
15 limitations that have been factored in to the RA program.

16 DR. JASKE: So are there reactions to what Mr.  
17 Johnson said?

18 MR. MINICK: Possibly just a clarification.  
19 Everybody is talking about fossil peakers. Some of these  
20 used from the resources might actually be hydro plants  
21 because they have not got sufficient water to run every hour  
22 of the month, so let's not say that this Resource Adequacy  
23 counting is just trying to pick on fossil plants, it is any  
24 plant that might have some ability not to run every hour of  
25 the month.

1 MR. VIDAVER: Like demand response.

2 MR. MINICK: Yes, like demand response.

3 MR. VIDAVER: Mark, do you have any idea how the  
4 portfolio of resources that Edison has for RA fits neatly  
5 into these buckets, how much latitude?

6 MR. MINICK: Right now, it is not a restriction to  
7 us because we have not got that many peakers. I mean, we  
8 could build four peakers. They do have use limits on them.  
9 We bid them into the Resource Adequacy. We think right now  
10 they are not inhibiting us as far as our resource  
11 accounting, overall. As we get more and more peakers that  
12 might have use limits, we probably would run into some  
13 problems with our resource adequacy fund.

14 DR. JASKE: I wonder if there is another dimension  
15 of this, and that is, as the system -- and this will  
16 probably be a gradual process -- moves more toward reliance  
17 upon the various preferred resources that, by law, or the  
18 policy makers have pushed by decision, renewables, demand  
19 response, etc., will that place -- and they all have  
20 limitations compared to, you know, a power plant that is  
21 capable of running 8,760, other than maintenance down time  
22 -- is that going to place greater pressure on the remaining  
23 such class of power plants that will operate, sort of fill  
24 in all the holes left by all these other resources that have  
25 sort of a must take quality to them? And is the ISO sort of

1 pursuing anything about that if it does perceive that as a  
2 problem?

3 MR. JOHNSON: The ISO, as you know, is very busy  
4 at trying to figure how to integrate for the future, you  
5 know, at the 20 percent renewable target, and the 33  
6 percent, and we are in the process of looking at resource  
7 needs. But you are right, Mike, we are going to need --  
8 there is going to be a different landscape going forward  
9 with a different resource mix than we have today. And it is  
10 going to be a different operating environment, much more  
11 challenging. You have heard us talk today about need for  
12 ramping capability, with the introduction of intermittent  
13 resources, and then we have heard, for example, Catalin this  
14 morning talking about inertia, where we would need a certain  
15 amount of mass as far as steel in the ground, power plants  
16 with mass, for example, in the LA Basin we would really  
17 continue to need that partly because of just the physical  
18 dynamics of the system, and then also the complimentary  
19 benefits it has for bringing in the imports, for allowing us  
20 to continue to bring in imports. But as far as -- you know,  
21 Mike, I think it is fair to say that that changed landscape  
22 will provide a bigger challenge for us to operate the system  
23 and it is probably going to change in some way the way we  
24 are using existing resources, and the way we will use  
25 resources in the future. I cannot say exactly how that

1 dynamic may play out, but one thing that we have observed in  
2 certain periods of operating, you know, we have to make  
3 plants go up, come on, move up, go down. Some of the plant  
4 operators are not always thrilled with the way we need to  
5 operate them, given certain system conditions. So in the  
6 future, again, that is going to be a real challenge. It is  
7 going to be important among the work the ISO is doing, in  
8 cooperation with the other agencies, is to try to figure out  
9 what an optimal resource mix will be, or at least a viable  
10 resource mix will be as we move into the next decade.

11 MR. MINICK: We are doing some studies -- I mean,  
12 we are helping [inaudible] on this particular thing -- my  
13 biggest fear is two-fold, as mentioned by some of the people  
14 that build peakers -- I do not expect peakers to run at full  
15 load all the time when they are on. When we do more and  
16 more intermittents, they are going to be started more, and  
17 will be penalized for a half an hour early start, and you  
18 think you are going to have two a day, now you might have 10  
19 a day, to make it more intermittents. That is the penalty  
20 that you are going to have to impose, which I think is -- I  
21 would not say silly -- but impossible to incorporate.  
22 Secondly, they are going to ramp up and down a lot, they are  
23 going to go from half load to full load to half load, and  
24 full load constantly, when you have all these intermittents,  
25 that -- if they are penalized like every hour of their run,

1 their counter is fully on for Emission Offset Credit  
2 reasons, they are not going to be that fluid all the time  
3 and that is going to be a problem. Your original question  
4 was how many offsets. We do not know yet. There are so  
5 many different possible outcomes and scenarios about what  
6 resources get built and why. We need different peakers for  
7 solar than we need for wind, and we need different  
8 resources, depending upon location, depending on voltage  
9 control in the system, so we cannot give you a number  
10 except, I told you in my presentation, it could be 2,500  
11 Megawatts or more. So we needed to at least get them when  
12 we started, and it could be 5,000, but we will not know the  
13 exact number until we do some more studies.

14 MR. SCIORTINO: Mike, can I offer kind of a  
15 mechanical -- it is not a huge solution -- but Larry alluded  
16 to it earlier in his presentation, that links the number of  
17 operating hours with the credits that you are getting. Now,  
18 Larry was very precise in saying that like people at GE will  
19 only guarantee a certain emission limit like, in our  
20 example, we were guaranteed three pounds PM-10 per hour of  
21 operation, so when we went through that exercise of reducing  
22 the number of hours of operation to try to fit under the  
23 1304 rule, what we kind of came to realize was that, wow,  
24 that is GE's guarantee? That is what you have to go for  
25 your permit? That limits the number of hours you get



1 permitted for? You always have the opportunity, and Larry  
2 alluded to this, six months down the road, in terms of after  
3 your commercial operation, you can ask the AQMD for another  
4 source test, and they will come out and they will measure  
5 what you are currently operating at. And historically, the  
6 LM 6000 is the only ones we have any experience with,  
7 historically they actually operate at 2 pounds per million,  
8 but GE does not want to guarantee that. So one of the small  
9 tweaks that you can do within the confines of the rules are  
10 you have a source test come out and if it comes out to be 2,  
11 then you get a new permit based on the 2 pounds, so you can  
12 actually increase your hours of operation by 33 percent. So  
13 in a sense, Larry, you touched on that. You said, well, if  
14 you buy them all at once, you have the option of either  
15 selling them back into the market because now you have got  
16 more than you need, or you can actually expand the number of  
17 hours that you can actually operate based on a revised  
18 permit. So it is kind of a small tweak in the system that  
19 allows you to increase some amount in terms of your hours.

20 DR. JASKE: But I guess I wonder, this is  
21 addressed to you, Mr. Nazemi, you know, were plants actually  
22 to operate in this mode where they are having very frequent  
23 starts, as Mr. Minick hypothesized, and ramping up and down,  
24 more so than just going up and staying at a constant level  
25 of output, you know, does that create worse air emissions,

1 and what might you need to do to adapt your permitting  
2 process to deal with that kind of change in operating  
3 regime?

4 MR. NAZEMI: Actually, I do not know specifically  
5 what the emissions would be a different percent load for  
6 each pollutant to answer the question, whether it will be  
7 worse or not. But I think what I can offer, and I think  
8 that is what we have offered to project is, that that may  
9 operate at partial load and not full load is not to penalize  
10 it by the hour, but rather by the amount of fuel they burn.  
11 So when we ask a project proponent, give us your worst  
12 monthly usage, we ask them what is the maximum amount of  
13 fuel that you use in one month, we will divide that by 30,  
14 and that becomes their daily liability for offsets. The  
15 question of, well then, what if we gave you an emission  
16 factor that is guaranteed by a manufacturer, and then later  
17 on we did a source test and it showed something lower, and  
18 then we want to change our permit, is somewhat problematic,  
19 in particular for pollutants that we cannot continuously  
20 monitor, because you can always count on a piece of  
21 equipment to do its best when you are doing a source test,  
22 and then a month later, or a week later, you do not know if  
23 it is operating at that level or not. But, for example, on  
24 our Reclaim Program, we do that with NO<sub>x</sub> because everybody  
25 has to have a continuous monitor, and you know exactly in

1 what day, in what month, and in what quarter how much NO<sub>x</sub>  
2 they emitted, and they are only held liable for that amount  
3 of NO<sub>x</sub> emissions. So I think it depends on the type of  
4 project and the partial versus full load can be addressed,  
5 so I think that is something that we do take into  
6 consideration, but to do a snapshot and say, "Well, now that  
7 we have found the perfect fit, let's change our permits to  
8 something different" is somewhat problematic, and I think we  
9 can only deal with those types of requests if it is a  
10 continuous monitoring scenario.

11 DR. JASKE: A question from -- that came out of  
12 perhaps Mr. Kostrzewa's presentation this morning, or  
13 earlier this afternoon, would a limit on -- would an  
14 alternative permitting process that focuses more on expected  
15 hours of operation and less on the potential with some kind  
16 of mechanism to make the District whole, should expected  
17 hours be exceeded because of some system operating  
18 conditions, Mr. Nazemi, can you foresee the District's rules  
19 shifting more towards that basis if there really was a  
20 legitimate basis for that sort of truing up so that we could  
21 minimize the gap between the expected level of emissions and  
22 emissions based on potential?

23 MR. NAZEMI: As long as it is consistent with  
24 federal and state law, yes.

25 DR. JASKE: And can you imagine the state and

1 federal processes adapting themselves to that change in any  
2 realistic period of time?

3 MR. NAZEMI: I think that is pure speculation. I  
4 do not know if my answer is going to be worth much. But I  
5 think it is important to keep in mind that there is --  
6 whenever you talk about federal law, you are having national  
7 implications, not just what is going on in Southern  
8 California, so that makes it that much more difficult. And,  
9 again, under state law, there are some hurdles that you need  
10 to jump over and you are not certain until you jump over the  
11 hurdle whether you are going to knock it down or not, and  
12 that is not the decision you make, it is someone else's  
13 decision, so it is kind of hard to really say, yeah, if we  
14 made this more reasonable, and everybody agrees this is more  
15 reasonable, but does that adhere to the law or not? That is  
16 the difficult part. I am sorry I cannot give you a better  
17 answer than that.

18 DR. JASKE: Does the developer group -- do you  
19 have any reactions to the question or his response?

20 MR. KOSTRZEWA: I agree that it would take an  
21 effort to get those rule changes made, but I would encourage  
22 the District to continue to think out of the box, as they  
23 have been. You know, if we could go from next month, to  
24 annual, to maybe a two or three year rolling, where every  
25 single pound was offset, but over a wider averaging period,

1 that would greatly diminish the problem. But, as Mohsen  
2 points out, that would take the will of the state to  
3 implement that.

4 MR. CARROLL: I mean, I think that there are  
5 certain constraints that are obviously imposed by federal  
6 law, and unless we want to go [inaudible], as I said  
7 earlier, everything should be on the table, including that.  
8 But if we assume for the moment that we are going to go out  
9 and try to propose solutions that fit within the constraints  
10 of existing federal law, I think there is still some  
11 latitude within those constraints to build additional  
12 flexibility into this permitting program. I think it is  
13 absolutely correct that state law needs to be analyzed, but  
14 I do not think that is a reason to move forward with these.  
15 I mean, as you can tell from these discussion, there are no  
16 easy solutions, if there were, we would have implemented  
17 them. So with respect to every single one of these  
18 solutions, we would say, well, no, there is that problem, or  
19 no, there is this problem, we will not get anything done if  
20 we allow that to stop us. So I think we move forward, you  
21 know, the District established the Resource Review Working  
22 Group, it met on a few occasions, I think there was some  
23 very good progress made on a number of the proposals that  
24 have been discussed today. That working group has not met  
25 for quite some time. I know that everybody has been very

1 focused on legislative efforts, but I think it would be very  
2 helpful to get that group reconstituted, and to pursue these  
3 issues. And some of them may require an analysis under SB  
4 288, if that is the case, then let's get on with the  
5 analysis. But I think that there is definitely room to  
6 maneuver here. That does not mean it is easy, but just  
7 because it is not easy does not mean that it should not be  
8 pursued.

9 DR. JASKE: So, Mr. Nazemi, earlier this afternoon  
10 I asked you what you thought the right forum was to pursue  
11 these issues, and your response focused on the sort of  
12 electricity need side of things. Mr. Carroll is obviously  
13 suggesting that the emissions side be examined in parallel,  
14 so is the District's NSR sort of working group process  
15 something that can take on -- if it has not already -- the  
16 emissions side of things, while perhaps the energy agencies  
17 try tackling the electricity system needs side of things?

18 MR. NAZEMI: I think our NSR working group is a  
19 good example that the District is willing and interested to  
20 look at all available options, that we have not made a  
21 decision that, no, we are not going to do anything. What I  
22 think is important to keep in mind is that that process is  
23 going to be time consuming, and if you are -- that is why  
24 maybe the reason that the energy analysis is also important  
25 is that, depending on what the timeframe is for the needed

1 electricity, that process may or may not work. I mean, if  
2 you are saying that you need these -- as was indicated  
3 earlier -- steel in the ground in 2010 and 2011, so that you  
4 can supply the power, then your permitting needs to happen  
5 like yesterday, and so this process is not going to help.  
6 But if you are looking into fixing the problem, not fixing,  
7 but maybe at least making it less burdensome, yeah, there is  
8 definitely room to work in. And as you heard Mr. Carroll,  
9 our agency's position is not that we are not willing to work  
10 on this, but I think we all have to realize we have come to  
11 a very unique and unusual time in our 40 plus years of  
12 experience in Air Quality, which is that we have been  
13 prohibited from permitting over 1,200 permits, that are  
14 worth a lot of investment, employment, and some of them are  
15 actual beneficial to the environment. And so we think it is  
16 more important to us than to get involved in a very long  
17 process of rulemaking and litigation on changing NSR rules  
18 when we have something more urgent on our hands, so we are  
19 not setting it aside, we are just doing what we think is  
20 necessary right now.

21 MR. CARROLL: But if we do not fix the NSR rules,  
22 the crisis that we are in the middle of right now is going  
23 to recur, and so you cannot put off fundamental issues that  
24 are precipitating the crisis in the hope to avoid it in the  
25 future. So, again, we have all had a lot on our plates, I

1 am not diminishing that in any respect, but I think we need  
2 to now turn to the underlying problems that precipitated  
3 this crisis and try to address it. And one of the issues --  
4 and I agree they are not going to be in place tomorrow, but  
5 one of the things that is going to get put on the table  
6 that, frankly, is one of the very few proposals that  
7 everybody, including the environmental community supported,  
8 is pushing off the deadline for having offsets in place  
9 until commencement of operation versus commencement of  
10 construction. If we put that fix in place, we have bought  
11 ourselves about two years to implement some of these  
12 solutions. So there is a package here that works, and I get  
13 a little frustrated with all this, "Oh, gee, it is too hard,  
14 gee, it takes too long, and you need to go first, and we'll  
15 wait to see what you come up with before we get started." I  
16 mean, everybody needs to come together and start working on  
17 these solutions, whether they are easy or quick to implement  
18 or not, because the problem is not going to get solved  
19 otherwise, and it is not going to go away with time.

20 DR. JASKE: Other sort of final comments?

21 COMMISSIONER BYRON: Gentlemen, I think we have --  
22 I feel like we have underutilized all of you, that there is  
23 discussion and it could continue, more than we can address.  
24 I would just like to take a moment, though, and turn to our  
25 representative from LADWP who we did not hear from during



1 this panel, and ask if there was anything in particular you  
2 wanted to add or say?

3 MR. MOORE: Yes, the AQMD had a solution to this  
4 problem when they promulgated Rule 1309.1, and it would have  
5 provided credits for electric generating facilities, and it  
6 was challenged on the basis that the CEQA analysis was  
7 inadequate. The idea was that the AQMD would have to look  
8 at all of the emissions impacts from the credits that would  
9 be dispersed from the credit bank in the coming years, even  
10 though each of the projects would themselves have to go  
11 through CEQA. One solution might be to amend the CEQA  
12 regulation to exempt the AQMD and such agencies from needing  
13 to go through CEQA when promulgating regulations relative to  
14 credit banks. The public health and safety would be  
15 protected, as I said, because each of the individual power  
16 projects would itself have to go through the full CEQA  
17 process. This would seem to be an easier lift than turning  
18 the problem over to the state, to a state agency. So I  
19 would ask Mohsen if this is something that the AQMD has  
20 considered, attempting to get the state CEQA regulation  
21 amended?

22 MR. NAZEMI: I feel like that is what we have been  
23 trying to do for the last year, and this is where we are.  
24 SB 696 initiated that process and it did not get anywhere.

25 COMMISSIONER BYRON: Gentlemen, I appreciate it,

1 but I think in the interest of time, we are going to go  
2 ahead and move to public comment. You are welcome to stay  
3 at the table because it might be an opportunity for a little  
4 more discussion as we get public comment, but I understand  
5 we are also getting late. Part of the problem is we started  
6 at 10:00 in order to make it easier for folks to travel here  
7 from the South. I hope you will stay and support the  
8 economy and have a good dinner here in Sacramento. But  
9 let's go ahead and move to public comments. And, again, you  
10 are welcome to leave, but you are welcome to stay because  
11 maybe there is some opportunity for some interaction. I do  
12 have a couple of blue cards, Ms. Korosec. Shall I go ahead  
13 and start with those?

14 MS. KOROSEC: Yes.

15 COMMISSIONER BYRON: We have got some patient  
16 folks that have been sitting here for the day absorbing all  
17 this information, and I will just take them in the order  
18 received. Jesse Marquez, Executive Director of Coalition  
19 for a Safe Environment. Mr. Marquez.

20 MR. MARQUEZ: I would like to thank you for this  
21 opportunity to speak with you in public comment, but I also  
22 have a grave concern. Our nonprofit organization is an  
23 environmental justice organization headquartered in  
24 Wilmington. We have members in over 25 cities in Southern  
25 California, which are mostly parents, residents, students,

1 elderly, as well as a few small businesses that support the  
2 work that we do. And our concern is that you have held a  
3 hearing today, or a workshop, whereby there is not one  
4 public interest ratepayer interest organization as a  
5 participant. We spent here seven hours approximately where  
6 you had the opportunity to hear the experts of all fields in  
7 the energy field, as well as governing agencies, but then  
8 where is the public's interest and the ratepayers' interest  
9 in participating? It is not there. So my first request  
10 would be of you, if you could hold another public meeting  
11 and invite public interests and ratepayer organizations to  
12 be able to provide comment to you, so you can see and hear  
13 an alternative perspective on what is being discussed today.  
14 Some thing that have been discussed have been regarding and  
15 in reference to the Clean Air Act, as well as CEQA. The  
16 majority of the U.S. public supported the Clean Air Act, and  
17 we believe in it, and it has worked very successful for us.  
18 California residents supported and voted for the CEQA law.  
19 It has been very effective and we support it 100 percent.  
20 There is no environmental justice organization in California  
21 or in the United States that wants to amend the Clean Air  
22 Act or the CEQA Act to make anything convenient for a  
23 polluter to do his business. And we do not want that to be  
24 one of the criteria. I am one of the litigants in the  
25 lawsuit -- we are being represented by NRDC. The South

1 Coast was found guilty of violating the law. In that sense,  
2 in the public's eye, it appears that they colluded with the  
3 power generating industry to get their demands met, and that  
4 is how it is viewed by the public. It was secretly done.  
5 Ron Wright's Bill was gutted in a minute, the last minute,  
6 there was no public participation in that. There was not an  
7 opportunity for all the different residents and  
8 organizations in the state of California to hold public  
9 meetings and testify and come to the Assembly Committees and  
10 Subcommittees, everything was done as a last minute thing.  
11 And that is not fair to the public to be able to do that. I  
12 am not an expert myself in energy generation, but I can  
13 share with you some of the experiences and some of the  
14 knowledge that I do have. I am also a member of RACE,  
15 Ratepayers for Affordable and Clean Energy. We are also a  
16 member of CARE, Californians for Affordable and Renewable  
17 Energy, and we are also a member of the Sierra Club Harbor  
18 Vision Task Force. And so, as a member of those, I also  
19 speak on our behalf with those references. Since we  
20 represent residents and the public, we look at the common  
21 sense model. We may not have a lot of computer models of  
22 other types, but some things are very common sense to us,  
23 and we have to look at very complicated issues. But we do  
24 have things that we do read in newspapers. I do attend many  
25 meetings. I do read quite a few documents, so I can have a

1 grasp of certain things. And one of the big fears and  
2 concerns we have right now is a word that is being used very  
3 freely, as pointed out by the gentleman over here, we are  
4 not in an energy crisis today. The last thing I read about  
5 our energy shows that we have about a 20 percent cushion.  
6 So there is a fear being generated that we have dire  
7 consequences for tomorrow or next year, which is not true,  
8 so there is no reason to ramrod things through when there  
9 does not have to be.

10 Now, do we see a necessity for planning for  
11 energy? Yes. We support planning 100 percent. But  
12 creating a fear that there is a crisis is not true, or try  
13 to hide it under the guise that we are in an economic crisis  
14 now and we need more jobs, we need to keep it in its proper  
15 perspective, so we do not see it as a crisis. You are going  
16 through a proper planning process and we need to have the  
17 public participate in that planning process. Do we see  
18 energy needs for the future? Yes, there is population  
19 growth, there is business growth, but then there is also a  
20 smart planning process. As an example, I participate on the  
21 Port of Los Angeles and the Port of Long Beach, and the  
22 refinery issues down there. Our participation at the Port  
23 and Harbor Commission meetings, just like your Commission  
24 meetings right here, is that we asked them years ago that  
25 why can't the ports have solar energy there when you have

1 thousands of acres of open space. And, no, they do not have  
2 to be 10 feet tall, they can be put on poles and canopies,  
3 you know, 40-50 foot tall, or even higher so they do not  
4 interfere with the normal container stacking. But after six  
5 years of asking for that, they listened. Last year, the  
6 Port and Harbor Commissioners voted to go forward with  
7 creating 10 Megawatts of solar power there at the Port of  
8 LA. They just approved a month or two ago the first  
9 contract for the first Megawatt of solar power. So in some  
10 cases, we are not talking about huge 500-800 Megawatt  
11 facilities, but we are realistic, too, we do see industries  
12 that are local and they do not need to have those big  
13 facilities, but they are looking at a smart approach, and we  
14 support 10 Megawatts of solar energy because they also did a  
15 little bit of a study to see what would their energies be  
16 over the next five to 10 years, and it came out to be about  
17 10 Megawatts. So that falls on that term that you use --  
18 distributed generation? Well, we consider this distributed  
19 generation. But we see, then, that they can also in the  
20 future go to 20 Megawatts, 30 Megawatts, and now we are  
21 working with the Port of Long Beach, and they have already  
22 informed us that they are looking at the potential for solar  
23 energy there, as well. Now, is there a wind energy  
24 application at the ports? Absolutely. In the evenings,  
25 everyone that lives by the coast know about if a wind has

1 come in, so we have asked both ports to look at wind energy.  
2 Now, some people are going to say, "Oh, yeah, well, then you  
3 are going to have to worry about the windmills killing the  
4 endangered species, birds," well, we have also looked into  
5 that, and we also realize that there are those vertical  
6 turbine windmills that do not kill birds -- we have seen  
7 them and there are different styles, I can actually show you  
8 a notebook I have of about 50 different applications of  
9 vertical wind turbines that would not hurt birds. But we  
10 see that as an avenue to go, as well, again, being  
11 distributed. We have seen nightmares occur. Last year,  
12 CPUC approved SEE to enter into a contract with NRG to  
13 repower a power plant that was closed down and built in 1929  
14 at the Port of Long Beach. I opposed it. I appealed it  
15 before the Board of our Commissioners of Long Beach, I  
16 appealed it before the City Council, I went before them. I  
17 said, "Here you are approving this power plant. It is going  
18 to have a certain amount of air pollution coming out of it.  
19 What are all the terms of this deal?" And when I looked at  
20 the terms of the deal myself in order to respond to our  
21 members in Long Beach and other communities, it was a \$300  
22 million contract for 10 years, \$30 million a year for them  
23 to be on standby for 150 hours. So I asked the Port of Long  
24 Beach, and I asked the City of Long Beach, all 15 Council  
25 members whether the City of Long Beach could negotiate with

1 that in their benefit. Is there a clause in that contract  
2 that the City of Long Beach or the Port will not be blacked  
3 out or browned out? The answer was no. So here is a nice  
4 signed deal and today, right now, there could be a black-out  
5 in Long Beach, and they have no benefit of that new power  
6 plant now coming online. I even asked NRG, "Could you  
7 invest some of that money in some solar energy, on public  
8 schools, municipal buildings, as a good gesture?" They  
9 refused. In fact, they did promise me that same, "Oh, we'll  
10 create a fund afterwards, maybe for some public education on  
11 energy conservation, etc." They never came through with it.  
12 So we do not see that as a good deal. Then we hear about  
13 BACT, Best Available Control Technology. Well, we have done  
14 research on Best Available Control Technology and we have  
15 some problems with it because AQMD can approve a technology  
16 as a BACT, and it could be a 95 percent effective one, it  
17 could be a 90, 80, 70, 60, 50 percent efficiency. All of  
18 them are called BACT. So, what I have to say about BACT  
19 now, it is not acceptable to us, the public, that have  
20 learned about BACT. What we want is MACT, the Maximum  
21 Achievable Control Technology, which means the number one  
22 best. Now, if a couple of competitors happen to be within 5  
23 percent of each other, I have no problems with that, but if  
24 there is a difference of 10, 20, 30, 40, 50 percent between  
25 the technologies, and one of these power plants is choosing



1 one of the least costs, which means least efficient  
2 technologies, then we have a problem with that because BACT  
3 is no longer acceptable to us, because when we do a little  
4 bit more research and find out there are companies that do  
5 have technologies out there that we feel are better, none of  
6 these companies are using them, and none of them are in the  
7 applications that you have approved at this point in time.  
8 And one of those happens to be the EMX Technology, two of  
9 the principals happen to be here, EmeraChem, and, well, we  
10 have an opportunity to read some of their documentation and  
11 to take a look at it, and we feel that they are one of the  
12 better, if not one of the top three best, but no one is  
13 incorporating their technologies into their facilities. So  
14 I think, before you approve a permit, then there should be  
15 one more public request that, where the public can come in  
16 and say, "Wait a minute, we looked at the equipment, they  
17 are not using the Best Available Control Technology, no  
18 permit should be issued until we can confirm what is the  
19 Best Available Control Technology," and that is not being  
20 done. I have now submitted public comments on 17 Title 5  
21 permits for the oil refineries and petroleum industry, and  
22 we asked AQMD, we wanted to know the efficiency factors of  
23 the equipment because you are putting it into the permit.  
24 We are still waiting now to hear and read any of that  
25 information, none of it has been provided. So we still have

1 no clue how efficient the equipment is at these facilities.  
2 So I think there needs to be some type of score card, rating  
3 system for equipment, so we have some idea how good is the  
4 system, how good is the technology. And what are other  
5 alternatives? I also found out about another piece of  
6 equipment that would be great for you to know --

7 COMMISSIONER BYRON: Mr. Marquez, I have other  
8 commenters. How much more time do you think you will need?

9 MR. MARQUEZ: Five more minutes.

10 COMMISSIONER BYRON: How about three?

11 MR. MARQUEZ: Okay. Oh, this is a piece of  
12 technology which is a hydroelectric. What it is, it is an  
13 inline system that goes into pipes, that could be a water  
14 line, oil pipe, any type of effluent line, and what it is,  
15 it is like a little generator, just like you have in a big  
16 dam.

17 COMMISSIONER BYRON: Mr. Marquez, we are well  
18 aware of the technology.

19 MR. MARQUEZ: Okay, but again, where is that  
20 figured in where it can be used and applied. It is not. I  
21 will also mention about mitigation funds. We support having  
22 mitigation funds to offset impacts in the community, but we  
23 also have terrible results with some of that. AQMD won a BP  
24 lawsuit, \$30 million, \$3 million a year for the next 10  
25 years. BP is located in Carson, Wilmington is right across

1 the street, West Long Beach is just downwind. So when the  
2 first \$3 million came up for mitigation, we did not see a  
3 dime of it, however, the Chairman of the Board issued \$1  
4 million to three of its favorite charities, of which he was  
5 on the board of directors of, that we discovered later.  
6 What happened the second year? To cover up that, the 15  
7 Board members divided up the \$3 million and each one got  
8 \$200,000 a piece. So what mitigation is being proposed, we  
9 the public want to be part of that process, to what are  
10 going to be the rules and regulations, and how it is going  
11 to be spent, and who gets to participate in getting approved  
12 to use that money because we are not benefitting from it. I  
13 can tell you right now, Wilmington, the public got less than  
14 \$50,000 worth of services out of the last six -- well, about  
15 \$9 million that has been spent right now. And I will be  
16 submitting some public comment. And I thank you for this  
17 time.

18 COMMISSIONER BYRON: Thank you. Adrian Martinez,  
19 Natural Resources Defense Counsel. Mr. Martinez, thank you  
20 for being here. I am sorry that other members of the  
21 organization could not be present today.

22 MR. MARTINEZ: That is fine. Good evening. I  
23 think what I am taking away is NRDC and probably other  
24 groups will be submitting some rather extensive comments on  
25 this process, and I think that will be useful --

1                   COMMISSIONER BYRON:  On the process?  Or on the  
2 content?

3                   MR. MARTINEZ:  On the content, oh, we might  
4 mention the process, but we will focus on the content.  We  
5 have heard several novel interpretations of the law that we  
6 might weigh in on; also, several proposals that, in fact,  
7 provided me grave concern, and I am confident once I take it  
8 back to my colleagues at NRDC, it will cause concern for  
9 them, including discussions of CEQA exemptions, amending the  
10 Clean Air Act, both the state and federal version.  I think  
11 these types of discussions need more vetting and I think we  
12 will go to our colleagues who are concerned with the  
13 integrity of the state and federal Clean Air Act, and the  
14 California Environmental Quality Act, and discuss what  
15 happened today and what transpired.

16                  COMMISSIONER BYRON:  What did happen today?  Maybe  
17 I missed it.  Did we suspend CEQA here today?

18                  MR. MARTINEZ:  No, just several proposals were put  
19 on the table, and I think my assumption is the Energy  
20 Commission will do its due diligence in examining all those  
21 proposals, and I just want to make sure what was primarily  
22 tilted towards one side of the debate, the discussion today  
23 was tilted towards one side of the debate, and I think it is  
24 informative if you go to the other side of the debate.  It  
25 was very important to have this discussion, I learned a lot,

1 and actually heard a lot of important views from several  
2 project proponents, the Air District, and several other  
3 interests. So we will be providing these comments and I  
4 think they will provide some clarity on our position,  
5 especially provide some perspective on the litigation, also  
6 the health concerns with several new power plants, and also  
7 put some perspective on the emissions credits as a whole.  
8 As was mentioned briefly, the power plants are one small  
9 portion of facilities that actually need credits. In fact,  
10 there are many other facilities needing credits, including  
11 hospitals and other facilities, and, in fact, the power  
12 plants used a lot of credits and that is why we are here  
13 today, that is why you have such a robust participation in  
14 this discussion. So we will be following up by the October  
15 6<sup>th</sup> deadline with some comments to the Commission.

16 COMMISSIONER BYRON: Good. Let me ask you a  
17 question or two.

18 MR. MARTINEZ: Yes.

19 COMMISSIONER BYRON: You are also a plaintiff, as  
20 I recall, in the litigation. Is that correct?

21 MR. MARTINEZ: Yes, NRDC is a plaintiff.

22 COMMISSIONER BYRON: You know, I was struck by the  
23 comments that you provide, and we welcome them, and we want  
24 them. No decisions were made here today and there is an  
25 implication, I think, in some of the concern you have

1 expressed. I really took from the presentations and the  
2 discussion -- everything seemed to be, in my mind, geared  
3 towards solutions and, yes, the table was open for  
4 discussion, all things considered. And, of course, what  
5 really was not described today is, well, what are we trying  
6 to provide -- I should not say it was not described -- maybe  
7 we should have started with what are we trying to solve  
8 here.

9 MR. MARTINEZ: Yes.

10 COMMISSIONER BYRON: And it would seem to me, and  
11 I am not an expert with regard to the litigation and its  
12 current status, that that is really what we are trying to  
13 address, is the pending litigation and the potential outcome  
14 from that. Can you speak to the issue, or will you be able  
15 to speak to the issue in your comments, what is the goal of  
16 your litigation besides proving, indeed, that somebody did  
17 something wrong? What are we trying to accomplish with the  
18 long run goal with the litigation?

19 MR. MARTINEZ: Yeah, we will address that in our  
20 comments. I mean, I think the goal of the litigation, the  
21 national litigation, has been skewed to one perspective  
22 today. I think there were two rules on the table that the  
23 Air District adopted, one was 1309.1, which allowed power  
24 plants access to the Priority Reserve, the second was an  
25 emission credit generating rule 1315. We initially sued

1 because there was not a CEQA analysis that was adequate. We  
2 have had several judges agree with us --

3 COMMISSIONER BYRON: I am sure you are right, I am  
4 sure the judges agree, and I am sure you right. I am trying  
5 to understand, what is the goal? What are we trying to  
6 accomplish with the litigation?

7 MR. MARTINEZ: Well, as you are well aware, with  
8 the CEQA remedy, it is an environmental analysis. There has  
9 not been an environmental analysis of the impact of Rule  
10 1315 and 1309.1. It is our understanding that the Air  
11 District is not pursuing Rule 1309.1, the amendments to  
12 allow power plants, and solely pursuing Rule 1350, at least  
13 I do not want to put words in their mouth, they might -- I  
14 do not know the state of what they are doing. But we  
15 continue to believe that there still needs to be an  
16 environmental review of Rule 1315 and its impacts on the  
17 Basin. There has not been much discussion that the Los  
18 Angeles region has some of the dirtiest air in the nation.  
19 We continue to fail to meet attainment. We are actually  
20 likelihood on this attainment deadline comes due in 2010.  
21 There was a promise made to residents that we would need  
22 attainment, and yet we are not going to meet that goal. And  
23 so NRDC, other groups, have a continued commitment to push  
24 the Air District to meet attainment. Now, concurrently,  
25 there is another goal, is to make sure that power plants,

1 especially fossil fuel powered power plants in the Basin are  
2 needed, and I think we continuously requested a needs  
3 assessment. I think that process is starting to progress.  
4 Several agencies need to discuss -- I actually disagree that  
5 there should be just wholesale building of power plants in  
6 the region, I am not convinced that is necessary. Now, the  
7 analysis is done and that is the conclusion, then I will  
8 look at that analysis, the numbers, and the information.  
9 And make an independent conclusion from that. It is not --  
10 from what was presented today, I am not convinced that the  
11 number of power plants slated for the region are needed.  
12 And, in fact, today we saw one power plant get removed -- it  
13 removed its application. So I think there are issues and  
14 there are power plants that may not need to be built, and  
15 that is what we are interested in. We are interested in  
16 that analysis and that process. There needs to be a public  
17 process which, as you described, having the information so  
18 people can tear into it and really understand why we are  
19 building these power plants, why we are building them in  
20 certain communities, and other considerations like that.

21 COMMISSIONER BYRON: Well, thank you very much for  
22 being here. I welcome your written comments and please  
23 remember, this is not a court of law. We are interested in  
24 solution-based comments, so if you have recommendations that  
25 you can make along those lines, they are more than welcome.



1           MR. MARTINEZ: And as are we, we are also  
2 interested in solutions. Mr. Carroll pointed out some areas  
3 where everyone kind of agrees, so we will point to those  
4 solutions in our comments.

5           COMMISSIONER BYRON: Thank you, Mr. Martinez.  
6 Okay, I could not read it at first, I apologize, Gary  
7 Rubenstein, Sierra Research. Thank you for your patience,  
8 Mr. Rubenstein.

9           MR. RUBENSTEIN: Thank you, Commissioner Byron. I  
10 know it is late, I will keep my comments brief. One of the  
11 speakers very early this morning, I think it was still this  
12 morning, made a comment about how an economist might assume  
13 a can opener as a solution to opening can of beans on a  
14 desert island. There is one assumption that has been made  
15 in virtually every presentation we have heard today, and  
16 that is the assumption that we actually know what the  
17 particulate emissions are from gas-fired power plants. What  
18 we actually know is what vendors guarantee, and what we know  
19 is what project developers assume is a level of risk behind  
20 that guarantee. This Commission co-sponsored research as  
21 far back as 2001 demonstrating that, if you used more modern  
22 methods to measure particulate emissions from gas-fired  
23 turbines, the actual emission rates are roughly 10 times  
24 lower than the numbers that you typically see in a licensing  
25 case. That was not a fluke. And there has been continuing

1 work that has gone on over the last eight years. Most  
2 recently, there were a set of tests that were done here in  
3 Sacramento with the Cosumnes Power Plant in a report that  
4 was just released, demonstrating that most of the  
5 particulate emissions that we think we are measuring are  
6 actually indistinguishable from the background that we were  
7 trying to measure it from. Basically we are stuck trying to  
8 measure zero. And a couple of speakers have alluded to how  
9 they have taken a risk on as project developers to try to  
10 license emissions rates that are maybe 20 percent, maybe 30  
11 percent lower than the render guarantee, but the underlying  
12 fundamental problem has to do with the test method. There  
13 are a couple of new generation test methods that have been  
14 developed. And before someone suggests that they have to be  
15 EPA approved, they are. Those methods demonstrate  
16 substantially lower emissions and, if you think about all  
17 the numbers we have talked about today, if you divide the  
18 particular emissions problem we are trying to deal with in  
19 power plants by 10, it fundamentally changes the calculus.  
20 Solutions that we think are insurmountable suddenly become  
21 potentially possible. The magnitude of the problem is just  
22 much better, and I would simply strongly suggest that you  
23 include in your analysis, review those test methods, ask the  
24 relevant air agencies what they think of the new test  
25 methods because, to the extent that we can develop some

1 support for the use of these methods and licensing  
2 procedure, and in compliance procedures, I think it becomes  
3 a much more manageable problem. Thank you.

4 COMMISSIONER BYRON: Thank you. And you bring up  
5 in a very short period of time something that addresses this  
6 issue, potentially, and in a substantial way. This is PIER  
7 research, I think, that you were talking about, PIER  
8 research projects -- Public Interest Energy Research funded  
9 project.

10 MR. RUBENSTEIN: The 2001 analysis was; the 2008-  
11 2009 study was privately funded.

12 COMMISSIONER BYRON: Mr. Nazemi, do you want to  
13 address this in any way, briefly, if you do not mind?

14 MR. NAZEMI: Really briefly, I think Mr.  
15 Rubenstein has been communicating with our agency in quite  
16 detail about these new test methods, and we have had our  
17 source testing experts review the methods and provide  
18 comments to the group that Mr. Rubenstein was working with,  
19 and we are working towards improving the test methods, but I  
20 think there were some specific concerns that we had with the  
21 test method, and I do not think it is the place to get into  
22 it here.

23 COMMISSIONER BYRON: Okay, but obviously you are  
24 aware of this and it is under consideration. I appreciate  
25 your comment, Mr. Rubenstein. If you can also figure out

1 who the lawyers can still get paid, somehow, so they can  
2 feed their families, then maybe we will have a solution  
3 here.

4 MR. RUBENSTEIN: Thank you.

5 COMMISSIONER BYRON: Thank you. The last card I  
6 have here at the Dais is Jeff Valmus, General Manager of --  
7 and I will let you identify it so I do not misstate it.

8 MR. VALMUS: Good evening. My name is Jeff Valmus  
9 and I am with EmeraChem Power. Our company is, since 1992,  
10 has been providing air pollution control equipment for  
11 stationary sources. We provide traditional technologies  
12 like SCR, and we also provide multi-pollutant, ultra-clean  
13 technology EMX. I want to approach this from a little bit  
14 different angle tonight and I have heard a lot of comments  
15 and discussion and concerns, obviously, over the amount of  
16 credits, the scarcity of them, whether that be PM or NO<sub>x</sub>  
17 credits, or the cost of those credits. And certainly those  
18 are all issues here. But what I have not heard is any  
19 solutions regarding it from a technological standpoint, and  
20 I certainly heard it from an alleged slate of viewpoints,  
21 policy viewpoints, and everything else. And I believe, as a  
22 member of the NSR Working Committee, that we need to look at  
23 all of those things, and they are all important, and there  
24 are many things we can do within that committee that can  
25 help provide solutions. I want to talk about a little bit

1 of advanced technology here. The EMX, the lean NO<sub>x</sub> trap  
2 technology, performs better than current BACT for all  
3 criteria pollutants. It is capable of generating these ERCs  
4 that are so direly needed for PM, NO<sub>x</sub> , VOCs, and for sulfur,  
5 because of its high availability to remove efficiencies.  
6 The guarantee level for PM from our system reduction is 50  
7 percent. That means every single stationary source that we  
8 are trying to permit here today, if it utilized our  
9 technology, would require 50 percent less credits in order  
10 to be put in place. At the same time, it will control NO<sub>x</sub>  
11 levels of below 1 ppm. It will also create sulfur  
12 reductions anywhere between 90 and 95 percent, and it will  
13 control CO at 99 percent, and it also has no ammonia slip.  
14 This is a game changer. It has the ability and what is very  
15 similar looking to an SCR type system to provide credits and  
16 PM and SO<sub>x</sub>, all that we need. It also provides a great deal  
17 of operational flexibility due to the ability to remove  
18 these emissions credits. We have heard a lot today about  
19 power plant developers having to put a lot of capacity in  
20 because they are not able to run a lot of hours there. This  
21 provides the ability to run a lot of hours. You now, all  
22 these simple cycle plants that are being considered here,  
23 you know, they have a lot of emissions when you can start  
24 from start-ups, to shutdown, transients, and when they  
25 operate at low loads, these emission levels go through the

1 roof. So EMX has the capability like NCR to be able to  
2 control those emissions during those times, so it also helps  
3 reduce it, and as such, you are going to be able to run one  
4 more hour in the long run. It is also commercially  
5 available right now. We have been operating for 10 years on  
6 ten plants, and with over 420,000 hours of operation at 99  
7 percent availability. It is a robust system, it is  
8 available now to help with the solution.

9 COMMISSIONER BYRON: Do you have any units in  
10 California?

11 MR. VALMUS: Yes, we have a unit up -- we have  
12 several units in California. The closest is the City of  
13 Redding, it is a 50 Megawatt facility, and it has been  
14 operating since 2002 at levels between .5 and 1.0 ppm NO<sub>x</sub>  
15 levels. At the same time, we just recently in 2007, summer,  
16 performed PM testing at that facility where we averaged over  
17 50 percent PM reduction through our systems. So we do have  
18 the results of that. It can help relieve a lot of the  
19 stress in the burden we are seeing here. It can also help  
20 with the ability to retire the OTC plants. It has the  
21 ability to generate ERC credits, not only lower the demand  
22 of new facilities, but it also has the ability to go  
23 retrofit and create an ERC. So I think it is an important  
24 technology that needs to be more considered in these kind of  
25 circumstances where we are looking to try to build power



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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission 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 meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 9<sup>th</sup> day of October, 2009.

  
PETER PETTY