INTEGRATED ENERGY POLICY REPORT STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	Docket No.
Preparation of the 2009 Integrated Energy Policy Report (IEPR)	)	09-IEP-1B
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

FIRST FLOOR, HEARING ROOM A

SACRAMENTO, CALIFORNIA

THURSDAY, AUGUST 6, 2009

9:00 A.M.

Reported by:
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COMMISSIONERS PRESENT

STAFF PRESENT:

Suzanne Korosec, IEPR Project Manager

SPEAKERS:

Jim Woodward, Electricity Analysis Office

Valerie Puffer, Power Systems Analyst
Glendale Water and Power

Brad Packer, Manager, Wholesale Energy Resource Management
Los Angeles Department of Water and Power

ALSO PRESENT:

Gena Dixon, Southern California Edison

Craig Lewis

Kathy Treleven

Jim Stewart

Tom Miller, PG&E

I n d e x

P R O C E E D I N G S

9:00 A.M.

MS. KOROSEC: Good morning, I'm Suzanne Korosec; I lead the unit that produces the Commission's Integrated Energy Policy Report. Welcome to today's staff workshop on Publicly Owned Utility Resource Adequacy.

The purpose of today's workshop is to get comments on a staff assessment of publicly owned utility resource adequacy and resource plans. Assembly Bill 380 requires each publicly owned utility to, this is in quotes, "prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves sufficient to provide reliable electric service to its customers. AB 380 also requires the Energy Commission to report on POU resource adequacy every two years, as part of the IEPR.

In December of 2008 we released forms and instructions for submitting electricity resource plans, and today's staff presentation is based on the information received from the POUs in response to that data request.

Our agenda today includes a presentation by Energy Commission staff, followed by presentations from Glendale Water and Power and Los Angeles Department of Water and Power. We'll then take public comments and hope to adjourn before noon.

Just a revision to the agenda, the Commissioners were unfortunately called away. They are unable to join us, but they wanted to make sure that the parties know that they're very focused on this issue and will be looking through the workshop transcripts and presentations to get up to speed on what went on today.

Just a few housekeeping items before we get started. The bathrooms are out the double doors and to the left. There's a snack room on the second floor, of the atrium, under the white awning.

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

Today's workshop is being broadcast through our WebEx conferencing system. So please be aware that the workshop is being recorded. We'll make the recording available on our website after the workshop, and we'll also have a transcript available in about two weeks.

For presenters and commenters, please make sure to speak directly into the microphone so the people on the WebEx can hear you speaking.

During the public comment period today, we'll hear first from people in the room and then we'll open up the lines for the WebEx participants.

For parties in the room making comments, please come up to the microphone at the center podium here in the room so we can make sure it's captured on the transcript. And it's also helpful if you can remember to give the court reporter your business card so we can make sure that your name and your affiliation are correct in our transcript.

We're also asking the parties to submit written comments and those are due by 5:00 p.m. on Thursday, August 20th.

So with that, I'll turn it over to Jim Woodward to get us started.

MR. WOODWARD: Thank you, Suzanne.

Good morning, I'm Jim Woodward and I'm proud to work in the Energy Commission's Electricity Supply Analysis Division. I would like to share with you some of the more interesting findings and assessments to be included in our staff report on resource adequacy and electricity resource plans of California's publicly owned utilities.

First and foremost, I would like to thank all the resource planning staff at publicly owned utilities throughout California. Their diligence and responses to our data requests made this presentation possible. Some utilities found it challenging to complete all the supply forms, especially those submitting them for the first time. Most utilities, however, were collaborative and timely as

together we worked to make these data sets accurate, complete, and reliable. I expect this cooperative effort will continue as utilities review, correct and update the information compiled by Energy Commission staff.

I would also like to acknowledge the expertise and dedication of my colleagues, co-workers, management, and leadership here at the Energy Commission. Without them, none of this work would be possible.

We have two other speakers on the agenda today. Valerie Puffer from Glendale Water and Power will be participating via WebEx. And Brad Parker will be here today from the Los Angeles Department of Water and Power. There should be time after each speaker for questions, comments, and dialogue.

Resource adequacy requirements address only one cause of potential involuntary load curtailments; occurrences when demand for electricity in a service area greatly exceeds all available supplies. Supply adequacy is important because such outages tend to be widespread, expensive, and disruptive. While electricity supply and demand must always be kept in balance during real-time grid operations, an operating reserve of additional supply resources is always required. Load serving entities. LSEs, typically procure sufficient resources months ahead, and often years ahead, to continuously maintain that operating

reserve margin in real time. This forward capacity procurement obligation is typically formalized as a year-ahead planning reserve margin.

The planning reserve margin is the amount of generating capacity, including interruptible demand under the control of the LSE, or balancing authority, that exceeds forecasted peak demand. It's often expressed as a percentage of peak demand. A commonly used planning reserve margin, adopted by most LSEs in California, is 15 percent. The 15 percent planning reserve margin has been a useful benchmark for measuring, monitoring, and even regulating forward procurement by LSEs on a month-ahead and year-ahead basis. The 15 percent planning reserve margin is often assumed to provide a level of reliability in which electricity supplies are adequate to meet demand for all but one day in 10 years, though that has not yet been confirmed in California by modeling studies.

The 15 largest POUs in California began 2009 with a substantial capacity surplus over and above their forecast peak demand plus planning reserve margins. That surplus totaled 1,359 megawatts.

Utility resource plans document the commitments by publicly owned utilities to continuously have adequate generating supplies through utility ownership or contractual agreements.

As we'll see in subsequent slides, POUs are making significant and successful efforts to add more renewable energy to their supply portfolios. For the 15 largest POUs, the amounts of renewable energy are expected to increase this year to 16 percent of retail sales, up from 11.6 percent in 2008. While this 16 percent forecast may be optimistic, the trend is noteworthy as state and local policies are being implemented through new renewable energy projects.

Over the long-term, several existing contracts for coal-fired energy imports will expire, which should reduce carbon dioxide emissions that would be attributed to those POU energy supply portfolios.

In 2008, the sum of all non-coincident peak loads for all publicly owned utilities was 15,952 megawatts. This sum does not include the California Department of Water Resources, DWR. The statewide total of annual peak load served by all LSEs was 70,473 megawatts. So the POU share of total peak load was 22.6 percent. Please note that these peak-hour loads occurred on different days and in different hours for different LSEs. These numbers do not represent coincident peak loads for POUs in the California ISO balancing area, or in the other four balancing areas based in other states that extend into far Northern or far Eastern California. But these numbers probably are equivalent to

coincident peak loads for those POUs in grid balancing areas operated by LADWP, SMUD, Imperial, and Turlock.

Altogether in California there are 40 POUs using a definition that does not include DWR, and we do that mainly because much of the 10-year forecast data from DWR is confidential. In this presentation we count the Northern California Power Agency, NCPA, as one of the largest 15 POUs. We do this because NCPA provided a 10-year resource plan and the result is a more complete assessment of long-term POU resource adequacy. NCPA serves as scheduling coordinator for 10 small POUs that have banded together in a Power Pool for the purpose of long-term resource planning, and for day-to-day integration balancing loads and resources.

The 15 largest POUs in California all had annual peak loads larger than 200 megawatts in 2008. These 15 POUs account for 95 percent of all POU peak loads statewide. As requested by the Energy Commission last December, these POUs filed a 10-year forecast of peak loads and annual energy needs, along with a listing of expected supply resources to continuously meet their electric service obligations. These forecasts were submitted in February and March of this year, using forms adopted by the Energy Commission. Those forms included, for the first time, a request for actual 2007 and 2008 capacity and energy data on LSE loads and resources.

The other 35 small POUs, with annual peak loads smaller than 200 megawatts, account for five percent of all such peak loads in California. This year, for the first time, the small POUs provided year-ahead capacity and energy supply plans, along with historic data for 2007 and 2008. Small POUs will be discussed briefly towards the end of this presentation, starting with slide 21. Until then, the information that follows refers to California's 15 largest POUs, unless noted otherwise.

Utility-controlled power plants using natural gas consistently provide 40 to 50 percent of all capacity requirements, as we will see more clearly with slide 8.

Several newly developed -- sorry.

The Firm Peak Demand forecast, as reported by POUs, in the maximum end-use load in a future year that utilities must be prepared to meet. The peak-hour demand includes the initial 1-in-2 demand forecast for end use customers, minus any adjustment for demand-side resources or new customer-owned distributed generation.

The Firm Peak Requirement is the Firm Peak Demand plus the planning reserve margin used by each utility. When planning reserve margins are included, the forecast firm peak requirement for the 15 POUs is 16,700 in 2009 and 17,900 in 2018. This would be an increase of seven percent in ten years.

Six of the largest 15 POUs serve loads in the California ISO balancing area, Anaheim, Riverside, NCPA, Silicon Valley Power, Pasadena, and Vernon. All six use a 15 percent planning reserve margin. In other balancing areas, a 15 percent planning reserve margin is used by SMUD, Imperial, Modesto, Turlock, and Redding. The 15 percent planning reserve margin has been a useful rule of thumb for LSEs, for procurement purposes, such that scheduled outages and forced outages of various plants, and load forecasting errors, and weather forecasting errors would still leave balancing authorities with a seven percent operating reserve margin that includes a mix of spinning and replacement reserves.

In the LADWP balancing area, the Burbank, Glendale, and LADWP utilities use the Western Electric Coordinating Council reliability criteria and operating reserve standards. These are detailed in the 2008 Energy Commission report on POU resource adequacy. In simple terms, these three utilities plan to have enough resources to cover the loss of their largest generation or transmission facility without load shedding, while maintaining adequate spinning, replacement, and regulation reserves. For LADWP the system reserve requirement is normally 1,106 megawatts.

The 15 largest POUs in California began 2009, as I

said, with a substantial capacity surplus over peak requirements, a surplus of 1,359 megawatts. In sum, they are very resource adequate.

In 2008, the sum of all 40 POU annual peak loads was 15,952 megawatts. LADWP and SMUD together account for 57 percent of all POU peak-hour loads.

For visual clarity, this slide shows the top ten shares of individual POUs. The next five in 2008 were Pasadena at 310, Burbank 309, Glendale 306, Redding 293, and Vernon at 204. These peak load amounts include end-use customer demand plus any firm sales obligations.

In 2007, this sum for all 40 POUs was substantially higher, 17,700 megawatts. In 2006, the sum for all POUs was even higher, 18,400, when many utilities saw record peak demand during the July 2006 heat storm.

The aggregate of 2009 forecast for peak demand are slightly less than 12008 actual peak loads, in part due to reduced economic activity during the current recession and, in part due to increase in demand-side resources.

Most large-scale capacity additions by publicly owned utilities are planned several years in advance and are often described in published Integrated Resource Plans. Note also that most of these additions since 2004 are for natural-gas fired plants, sited locally in utility service areas.

One example may suffice to indicate how much time is needed to plan and develop these compact, highly efficient new fossil plants. Roseville filed an Application for Certification in October of 2003, which was accepted as data adequate two months later. The project approval decision by the Energy Commission in April 2005 mandated zero liquid discharge standards and use of best available control technology for emissions. Normal output for the combined cycle plant is 120 megawatts, with the ability to peak-fire to 160 megawatts during summer peak demand periods. Roseville Energy Park went online in October 2007 after a 24-month construction period.

The first listing in this table may underestimate the investments by LADWP in new capacity at Haynes. The net increase of 49 megawatts includes a new 575 megawatt combined cycle plant, less the retirements of Haynes 3 and 4, that were each 230 megawatts, and the de-rating of Haynes 6 by 81 megawatts.

The five-year focus on capacity additions that are mostly fossil is complete for now, except for finishing the second 98 megawatt unit at Riverside Energy Center.

Several newly developed projects are coming online this year to deliver renewable energy to California POUs. Some are local projects; many are located in other Western states.

Turlock Irrigation District, TID, is now getting energy from the 136 megawatt Windy Point project in south-center Washington, on a ridgeline north of the Columbia River. This 82 turbine project went online in May of 2009. In July of this year the Tuolumne Wind Project Authority, created by TID, closed escrow on the project for $385 million. Phase two at Windy Point is expected to bring another 200 megawatts online later this year, some of which will be dedicated to TID.

The Pine Tree Wind project developed by LADWP in the Tehachapi's is now online. The Milford Project in Utah is being developed by the Southern California Public Power Authority. LADWP has a 188 megawatt share of this 200 megawatt project that has 80 wind turbines, each two and a half megawatts.

In July of this year Imperial Irrigation District submitted compliance applications to the Energy Commission according to the Greenhouse Gas Emission Performance Standard regulations to that Imperial can develop a 15 megawatt biomass unit in 2010. There are many, many more small renewable energy projects in the pipeline, too numerous to list here, especially for landfill gas and distributed generation.

The first thing to notice in this slide is there are no sudden or dramatic year-to-year changes evident in

this composite perspective. Stability and continuity during the forecast period are the hallmark of POU plans to retain and acquire adequate electrical generating capacity. All things considered, stability and continuity are good things upon which improvement plans can be solidly based.

Let's look at the top category in this chart. Short-term and spot market purchases are projected to supply the last 450 to 800 megawatts that utilities are likely to procure in a given year. But these amounts, Short Term Purchases, do not include identified long-term resource needs for additional capacity. For example, by 2018 Modesto will need to add another 307 megawatts and SMUD will need to add another 347. Other POUs, such as Anaheim and Silicon Valley Power, expect existing and committed resources will result in modest capacity surpluses throughout the planning horizon.

The net result for all 15 POUs is that the top of this procurement stack, when compared to the Firm Peak Requirement in slide 4, has an expected surplus of 900 to 1,200 megawatts each year, though some of this net surplus in later years can be attributed to projects that are still on the drawing boards.

Utility Natural Gas is the central procurement category in this slide. Some additional capacity from natural gas-fired power plants will be needed to meet

forecast peak loads. Dependable capacity at utility-controlled gas-fired plants was just over 7,500 megawatts in 2009, equal to 45 percent of all supply resources. This percentage is remarkably stable over time. By 2018 POUs plan to have 8,320 megawatts available from utility gas plants, equal to 46 percent of all supply resources in that year. At most, it would be nearly 50 percent of all capacity in 2012 and 2013.

By 2010 Redding expects to add 50 megawatts to its 135-megawatt Redding Power Plant.

By summer of 2011 Anaheim expects to have 50 megawatts from its new Canyon Power Project, and an additional 150 megawatts in 2012.

Modesto plans to add a reciprocating plant, with 48 megawatts, in 2012.

Also by 2012, Imperial plans to re-power its aging fossil plant El Centro 3, for an additional 180 megawatts. And Imperial plans on 100 megawatts from new geothermal resources at Salton Sea by 2012.

While planned additions like these are site-specific and reasonable, there is always some uncertainty about successful project permitting, financing, completion, and even more uncertainty about online dates.

Some newly built capacity will be needed simply to replace aging coastal plants that use once-through cooling.

By 2013 LADWP expects to add six combustion turbines at Haynes, with 600 megawatts, so that the aging Haynes units 5 and 6, with 565 megawatts, can be retired or repowered.

By 2014, LADWP plans to have a new 260 megawatt combined cycle unit at Scattergood and a stand-alone 38 megawatt digester gas facility so that the aging Scattergood units 1 and 2, with even more capacity, 336 megawatts, can be retired.

At the end of the forecast period, in 2018, existing and planned utility-controlled power plants fueled by natural gas and coal are expected to provide 10,300 megawatts of generating capacity. After 2018, LADWP expects to replace, with renewable resources, its 477 megawatt ownership share in coal-fired Navajo Generating Stations. We'll discuss Utility Coal in more detail with slides 19 and 20.

At the base of this slide, nuclear power to meet summer peak loads is a constant 494 megawatts.

Hydroelectric power for the 15 largest POUs is 5,000 megawatts in 2018. The only significant change through 2018 is that SMUD plans to add a 390 megawatt pumped storage facility for 2015.

Non-renewable contracts for dependable capacity will decline over time as existing bilateral contracts expire. Existing contracts provide 19 percent of all

capacity needs in 2009 and this share declines to 10 percent in 2018.

Utility-owned resources, renewable resources other than hydro, represent a very small share of capacity that is counted on for reliability. These amounts may increase from just over 200 megawatts to 540 in 2018, but it would still represent only three percent of all capacity requirements. As a capacity resource, for example, LADWP counts on Pine Tree Wind for 12 megawatts, which equals 10 percent of its nameplate.

Dependable capacity from renewable resources under contract may increase from less than 900 megawatts to more than 1,200 in 2011.

Let’s see, am I on slide -- sorry.

The increases in energy from renewable resources will be much larger, as we’ll see later. By 2011, Riverside expects Shoshone geothermal energy to provide 36 megawatts, with plans that increase this to 96 megawatts in 2013.

SMUD counts on existing renewable contracts for 147 megawatts now, this increases to 194 during 2010 as 14 new biomass resources are developed, but then it drops to 66 megawatts in 2016 as existing biomass, small hydro, and wind contracts expire.

LADWP expects the capacity value of its renewable contracts to increase from 100 megawatts to 925 in 2018.

However, about 800 megawatts of this additional capacity would be from biogas, geothermal, and wind projects that re not yet specified or under contract. LADWP presently has 42 megawatts in distributed generation under contract.

The 20,000-foot view of POU energy supplies is very similar to the view of capacity resources. All 40 POUs together supply slightly less than one-quarter of total grid-connected electricity needs in California and the 15 largest POUs account for 94 percent of all POU energy procurement.

For the long-term, through 2018, the State's largest POUs, in aggregate, are forecasting relatively slow growth in the amount of energy required to meet customer demand. In 2008, the total Firm Energy Requirement was just under 68,000 gigawatt hours.

This procurement requirement is roughly 10 percent higher than total retail sales, primarily due to transmission losses and distribution losses. Also, six POUs had firm wholesale or energy exchange obligations that totaled 2,500 megawatts [sic].

The largest was Turlock's supply obligation to Merced Irrigation District, about 1,200 gigawatt hours. The second was LADWP's obligation to DWR for 568 gigawatt hours in 2008, related to water that passes through LADWP's Castaic plant on the West Branch of the California Aqueduct.

This energy amount was down 27 percent last year from average, as much less water is getting to Southern California.

Electricity sales to retail customers of the largest POUs totaled 60,600 gigawatt hours in 2008. The forecast amount for 2009 is slightly less. Combined retail sales in 2018 are project at 65,500, an 8.6 percent increase in ten years.

At first glance, the 2008 energy needs for all 40 POUs looked much like the 2099 peak load capacity shares in slide 11. LADWP, the nation's largest municipal utility, and SMUD are each in a class of their own. Together, they account for 55 percent of all POU energy needs. Among the top ten POUs, Silicon Valley Power ranks higher on energy than capacity due to a predominance of baseload-type industrial customers.

In the forecast period through 2018, the most significant trend is an increased supply of electricity from renewable sources, especially those to be developed under long-term contracts, this band of green, third from the top. This slide presents an aggregate profile of POU energy supplies, including all planned resources, as reported on POU supply forms.

There are some constants in the energy balance equation. Nuclear energy, at the bottom base of this chart,

is expected to provide a steady 3,600 gigawatt hours per year from Palo Verde and SONGS. Riverside is the only utility to own shares in both nuclear power plants.

Total energy supply from utility fossil resources, in aggregate, is expected to remain relatively unchanged, starting at 42,500 gigawatt hours in 2008, and ending the forecast period down four percent at 40,800 gigawatt hours in 2018. The aggregate 1-in-2 forecasts for utility fossil energy never exceed the 2008 actual amount when natural gas generation was well above average to make up for reduced hydro generation.

Fossil fuel plants provide most of the electricity used by public power customers in California. Utility natural gas and coal plants, combined, produced 63 percent of electricity required in 2008. Due to load growth, and the expected increase in other supply categories, the share of energy from fossil fuels declines to 57 percent in 2018. For Anaheim, Glendale, Pasadena, riverside, SMUD, and Vernon, the share of total energy requirements from utility fossil plants will change by less than five percent.

For other utilities the absolute amounts and the share of fossil resources in a portfolio will change substantially. Burbank plans to reduce energy supplies from coal-fired Intermountain and gas-fired Magnolia from 1,000 gigawatt hours to 750. Riverside forecasts their utility

fossil supply to decline from 1,333 gigawatt hours in 2008 to 1,100 in 2018. By volume, the largest reductions in fossil energy supplies are forecast by LADWP, from more than 20,000 gigawatt hours in 2018 to 15,000 in -- I'm sorry, that was 20,000 in 2008 to 15,000 gigawatt hours in 2018.

These reductions in utility fossil fuel electricity production will be partly offset by increases of about 2,200 gigawatt hours per year at plants controlled by Imperial, Redding, and Silicon Valley Power.

One utility is noteworthy for having utility fossil energy supplies equal to 102 percent of its total 2008 energy requirement, which may be a little too resource adequate. This share will decline to 86 percent by 2018. Anaheim has "take-or-pay anyway" fossil energy from coal-fired Intermountain and San Juan Unit 4, and from gas-fired Magnolia. Anaheim also owns a combustion turbine for peaking energy and is developing the Canyon Power Project to provide additional peak period energy starting in 2012. Anaheim is using the spot market and short-term contracts to sell its surplus energy. As purchases of renewable energy supplies increase, Anaheim will likely be selling surplus energy in amounts averaging 500 gigawatt hours per year.

Non-renewable energy from existing bilateral contract supplies will decline as contracts expire. Imperial has contracts with El Paso Electric and Shell

Energy North America that delivers 1,700 gigawatt hours annually through 2011.

Hydroelectric energy is a significant supply component for these utilities, averaging 5,800 gigawatt hours per year. 2007 and ’08 were very dry years. Energy production was down to 78 percent of average in 2007, and was 67 percent of average in 2008. No significant new sources of hydroelectric energy are expected through 2018.

Actual short term and spot market purchases in 2007 and ’08 averaged 6,400 gigawatt hours, much larger than the forecast average for all forecast years, 3,400 gigawatt hours. This difference, though, is not significant and here’s why; utilities plan to have adequate energy supplies for all hours in the year, primarily using utility-controlled fossil or hydro plants to ramp up and down, synchronized to daily and seasonal rhythms in demand, and to integrate intermittent renewable energy as it becomes available, or not.

While older utility-owned fossil plants are needed for local reliability, these plants often have high heat rates and are expensive to operate. So whenever cheaper energy supplies are available from other parties, utilities will lower their costs by replacing utility-owned generation with market purchases and with bilateral purchases from other LSEs with surplus energy. For example, Turlock

purchased over 1,000 gigawatt hours in 2007 and '08 using short-term contracts, but Turlock does not plan to rely on such purchases for any of its future energy needs.

State law requires publicly owned utilities to adopt and implement a Renewables Portfolio Standard, RPS. Unlike investor-owned utilities under CPUC jurisdiction, POUs are given flexibility to develop utility-specific targets, timelines, and resource eligibility rules.

The RPS targets in this slide have been published by the Energy Commission in a December 2008 consultant report prepared by KEMA, and posted on our website, and we have learned of some updates. For example, on Tuesday, Mike Pretto called me, from Silicon Valley Power, to say the City of Santa Clara, last October, adopted an RPS target of 33 percent by 2020.

That leaves Redding as the only POU here that has already reached and exceeded its RPS target. Some others, like SMUD and Roseville, are close. And really, there is much work to be done by all utilities.

The 10 POU members of the NCPA Power Pool have each adopted their own RPS goals, with significant diversity in timeframes and counting conventions. The 38 figure for 2008 is an estimate by Energy Commission staff, using a variety of sources.

As a short-term staff forecast, I expect this

table will be subject to additional scrutiny, updates, and corrections in the near future, perhaps even during this workshop.

The largest 15 POUs generated and purchased about 7,000 gigawatt hours of renewable energy in 2007 and ’08, equal to 11.6 percent of total retail sales in both years. Based solely on utility resource plan filings, the aggregate forecast for renewable energy supplies in 2009 is 9,900 gigawatt hours, which would equal 16.4 percent of retail sales. POUs have project specific plans to increase this to at lest 20 percent by 2011.

Among POUs, there are several conventions that define what counts as renewable energy. LADWP counts as renewable all the energy from its Gorge and Aqueduct hydroelectric plants. Those powerhouses, with output larger than 30 megawatts nameplate, annually generate bout 650 gigawatt hours. Note the scale. LADWP does not count as renewable 1,100 gigawatt hours per year from Hoover and Castaic.

Glendale and LADWP both include energy from landfill gas or digester gas that is burned with fossil fuels in their Grayson plants -- Grayson and Scattergood plants, 86 and 147 gigawatt hours per year, respectively, for the biomass value.

For CPUC-jurisdictional LSEs to count this as

renewable energy, biomass combustion must occur in a facility that does not use fossil fuel, or is specifically designated as countable in special legislation.

LADWP and SMUD include the renewable energy attributes of customer-owned distributed generation being developed as part of the California Solar Initiative, CSI. Even by 2012, however, CSI contributions will be modest; 150 gigawatt hours for LADWP, 54 by SMUD. By 2018, however, CSI is expected to supply 648 gigawatt hours to LADWP and 183 to SMUD, about a four-fold increase in six years.

In the NCPA Power Pool, eight of ten POUs count large hydros as renewable, but this does not include the largest utility, Palo Alto. As another example of POU-defined renewable energy procurement, the City of Palo Alto has been ramping up the purchase of renewable energy credits, RECs, to help meet its interim RPS targets.

Contracts for renewable energy supplied just over 4,000 gigawatt hours in 2007, and nearly 4,500 gigawatt hours in 2008. This procurement category is forecast to grow rapidly to 9,300 gigawatt hours by 2011. LADWP expects renewable energy supplies under contract to grow from less than 1,200 in 2008 to nearly 4,000 gigawatt hours in 2011. If these plans work and deliver as expected, contractual renewable energy supplies would account for 72 percent of all renewable energy for these 15 POUs.

Over the next ten years, significant increases in contracted renewables are expected by Anaheim, Burbank, LADWP, Riverside, and Turlock.

If all reported plans come to fruition, renewable energy from utility=controlled resources, other than hydro, will increase from 1,400 gigawatt hours in 2007 to 1,500 in 2008, to 2,000 in 2010-11. While this quantity will increase, the utility-controlled share of renewable energy supplies would decline from 20 to 17 percent.

The category of POU qualifying renewable energy appears to be growing after 2008. This apparent increase only reflects an expectation that hydroelectric energy production will be closer to average in 2009 and beyond, after two very dry years.

Hydroelectric energy generated along the two Los Angeles aqueducts was down by a third over the past two years.

Generic renewable energy is a term used on the supply forms. It represents utility commitments to meet their adopted renewable portfolio standards. How these commitments will be met with specific resources under contract or being developed is often unknown, especially toward the latter part of the planning horizon.

This category does include plans and commitments by some POUs to purchase, as available, renewable energy in

spot markets or with short-term contracts.

Source technologies for renewable energy supplies are summarized here, in slide 17. The amounts in forecast years include all existing and planned resources with a specified technology type, though for a few near-term projects the locations or counterparties are not yet identified. In 2007, the largest share of renewable energy came from wind, 1,600 gigawatt hours, closely followed by geothermal. Wind energy production is expected to increase quickly and substantially, with several new projects coming online in 2009.

Riverside is the leader in geothermal energy, with major increases expected in 2009, ’12, and ’13. NCPA and Silicon Valley Power already have developed utility-owned geothermal resources in the Geysers. Imperial plans to develop its own geothermal resources that may produce 750 gigawatt hours in 2012 and as much as 1,800 gigawatt hours by 2018.

Biomass energy will more than double, from 800 gigawatt hours in 2007 to 900 in 2008, to 1,700 in 2010.

Solar projects are negligible through 2011, but are expected to grow rapidly thereafter, especially with CSI programs and other projects not yet specified.

This slide repeats data from slide 14, with additional data from the three large investor-owned

utilities that also submitted ten-year resource plans to the Energy Commission. Using the POU qualifying metric, which comes from the KEMA Consultant report, the 15 largest POUs are expected to catch up and pass the three IOUs this year.

The IOU percentages represent the sum of all Energy Commission-eligible renewable energy as a percent of combined retail sales. This number could be higher, somewhat higher, if IOUs were allowed to purchase RECs for RPS compliance, as indicated by San Diego Gas & Electric in its resource plan. Four Southern California Edison and PG&E, the retail sales data for 2009, ’10, and ’11 are confidential, so we cannot present a more detailed comparison. Again, what may be most important is the trend, not the precise statistic or metric.

From 2007 through 2022, total quantities of coal-fired energy for the 15 larges POUs are scheduled to fall from 21,000 gigawatt hours to 13,200 in 2022. That is a reduction of 37 percent over a span of 15 years, with most of that reduction occurring after 2018.

In 2010 we see a small drop of 340 gigawatt hours, after Riverside’s contract with Deseret expires. Larger reductions occur after 2019 -- in 2019, after Turlock’s contract with Portland General Electric expires, and in 2020 after LADWP’s contract for Navajo generation expires.

For the 15 larges POUs, coal-fired generation

provided 31 percent of energy requirements in 2007. This share is forecast to decline to under 25 percent in 2018 and to less than 18 percent of total energy needs in 2022.

Dependable capacity from coal-fired resources declined from 2,300 plus megawatts in 2007 to 1,700 plus megawatts in 2022. Coal resources are relatively less important to meeting annual peak loads. The share of forecast peak requirements to be met by coal resources declines from 14 percent in 2009, to nine-and-a-half percent in 2022.

These are long-term resources that cannot be extended or replaced with other long-term coal contracts due to the state's Emission Performance Standard for greenhouse gasses. A residual 1,000 megawatts in capacity and 7,000 gigawatts of energy will likely remain in utility portfolios through the 2020's and beyond, unless POUs divest their ownership shares in coal-fired generation.

This table lists various POU long-term contracts for coal-fired generation, sorted by expiration date. Four particular coal-fired resources will be part of the supply portfolio for years to come; Boardman in Oregon, owned by Portland General Electric, Navajo Generating Station in Arizona, Intermountain Generating Station in Utah, and San Juan Generating Station in New Mexico. By the way, environmental upgrades at San Juan were completed in May

2009, at a cost of $330 million, to substantially reduce emissions of mercury, sulfur dioxide, and nitrogen oxide.

This table has been corrected several times since first posted on our website last week. The first correction was to delete a listing for Glendale that mistakenly attributed their exchange contract with Portland General Electric to a unit-contingent Boardman supply, and that is not the case.

Secondly, please note Turlock does have a unit-contingent supply from Boardman, and that contract expires after December 2018, not 2013.

Third, there is one additional contract that should have been included in this table. Riverside has a contract with Utah Power and Light that expires at the end of 2009. Under this contract, the Deseret Power Cooperative has supplied 52 megawatts and about 400 gigawatt hours of energy each year from the Bonanza or Hunter coal-fired power plants.

A fourth correction relates to energy supplied by Intermountain to LADWP.

LADWP, as we understand it, has three contracts for as-available power and energy from Intermountain. Two of these three contracts are now combined on one line in this table. LADWP has a 45 percent entitlement share in Intermountain equal to 803 megawatts, plus a four percent share purchased from Utah Power and Light equal to 72

megawatts. These two contracts total 875 megawatts and expire after December 2027. We think this line should show on 5,945 gigawatt hours, which is 1,153 gigawatt hours less than the amount shown on the web-posed slide and in the handouts.

LADWP also has a contract with the Utah Associated Municipal Power Systems, whereby the Utah municipals determine each year how much power and energy is excess to their needs, which is then designated for sale to LADWP. On a year-ahead basis, this resource seems not to have any dependable capacity value, but does supply 1,153 gigawatt hours in annual energy.

The 2008 Integrated Resource Plan by LADWP expected the Utah municipals would completely recall this power within four years. In the current economy, that may not occur until 2016. As a component in the previous slide, I chose to value it at 100 percent through 2012, stepping down to zero percent in 2016.

The total energy supply from Intermountain to LADWP is currently about 7,000 gigawatt hours per year.

As noted on the last line of this slide, the California Department of Water Resources has four years, now, to replace 154 megawatts of dependable off-peak power from Reid Gardner Unit 4, northeast of Las Vegas, Nevada. Reid Gardner’s contribution to DWR’s coincident peak load is

zero, as the unit can be recall by NV Energy to meet its summer peak loads.

There are eight POUs with an annual peak load grater than 30 megawatts and less than 200 megawatts, listed here from largest to smallest. These eight utilities have customer loads that are large enough and sufficiently stable to facilitate long-term resource procurement. Those first two acronyms are for the City and County of San Francisco and for the Power and Water Resources Pooling Authority.

For 2009, their annual peak loads sum to 612 megawatts, equal to 3.7 percent of the statewide POU total. By early 2009, each utility had acquired sufficient capacity to meet their 2009 peak loads, plus a 15 percent planning reserve margin that they were using.

In aggregate, these eight POUs have 1,014 megawatts in dependable capacity, for a remarkable 36 percent planning reserve margin. But this aggregate number is skewed by including 375 megawatts from San Francisco's Hetch Hetchy system, while the peak load for San Francisco, peak municipal load, is only 142 megawatts.

The inclusion of Hetch Hetchy hydro also skews the aggregate sources of energy supplies. Even in dry 2008, all San Francisco municipal demand could still be served by Hetch Hetchy generation with 350 gigawatt hours to spare, surplus energy made available for sale to other POUs. For

the other seven POUs in this group, the majority of their energy supplies came from non-renewable bilateral contracts or from utility-controlled fossil resources.

Azusa, Colton, and Banning have a long history of service in their cities. All three, years ago, acquired small shares in Hoover hydro, Palo Verde nuclear, and coal-fired San Juan unit 3. Colton has a 10 megawatt share in Magnolia, and also has a 43 megawatt gas-fired peaker named Agua Mansa. And Colton also has landfill gas to burn at a stand-alone facility. Azusa and Merced have contracts for wind energy from Solano, and Azusa will soon be getting energy from the new Garnet Hill wind project near Palm Springs.

There are 17 POUs with annual peak loads less than 30 megawatts. Some have large, but sparsely settled service territories, such as Trinity, Lassen, Surprise Valley, Anza Electric, and Needles. Most are relatively new -- most very small POUs are relatively new urban enterprises, serving only selected areas of their cities; Corona, Moreno Valley, Rancho Cucamonga, City of Industry, Cerritos, Victorville, Hercules, Port of Stockton, and Pittsburg, which serves the mare Island community of Vallejo.

For 2009, the sum of forecast peak loads for this group is only 211 megawatts, equal to 1.2 percent of all POU peak loads in California. When the planning reserve margins

are adding, which are not always 15 percent in this group, the total peak requirement for 2009 is 231 megawatts. If all these POUs used a 15 percent planning reserve margin, their combined firm peak requirement would be 12 megawatts higher; 243 megawatts. In their resource adequacy filings to the Energy Commission this year, one firm capacity procurement totaled 240 megawatts, one megawatt higher, and another 18 megawatts was set to be purchased under short-term contracts or in spot markets. As a group, they are resource adequate.

Utility-owned fossil resources are far less common among very small utilities, but there are some examples. Corona counts on 14 megawatts from the 30 megawatt Clearwater Cogen combined cycle plant.

Cerritos owns a 13 megawatt unit-contingent share of Magnolia, a share that does not cover all of its 15 megawatt forecast peak load, but does produce more energy than Cerritos needs over the course of a year. So Cerritos relies on the trading desk of Shell Energy North America for additional energy purchases during peak hours and sales of surplus energy during off-peak hours.

Some bilateral supply contracts are relatively open-ended. The City of Industry has an evergreen supply contract with Sempra that renews automatically month-to-month. For Industry, Sempra purchases up to two megawatts

in spot markets to supplement a three megawatt flat block contract.

Several POUs, very small POUs in this group, rely on federal agencies for the business of resource planning and generation supply.

Western provides full energy requirements, including scheduling, for Lassen, Trinity, Pittsburg, and Shelter Cove. The Phoenix office of Western provides nearly the same energy needs for Needles. And the Bonneville Power Administrative supplies all the electricity needed by Surprise Valley.

In 2008, short term and spot market energy purchases accounted for 4.5 percent of all energy procurement in this group, which is comparable to averages for larger utilities.

For renewable energy, Rancho Cucamonga received eight gigawatts hours from landfill gas contracts in 2008 and expects an increase to 30 gigawatt hours this year. Other than that, it's pretty much the large hydro in Western and BPA portfolios that is counted as renewable energy by the smallest POUs.

I would like to finish this assessment by accenting the positive aspects of POU resource plans and resource adequacy. This year we received filings from 50 POUs, counting DWR, and all ten members of the Power Pool at

NCPA. Getting these filings from all the smallest POUs was no small accomplishment. This effort at completeness, though, should give confidence to the conclusion that POUs, large and small, are acting prudently and responsibly to procure adequate supply resources that maintain current reliability standards and at the same time address important energy policies.

The Energy Commission is monitoring and reporting progress in these areas, progress than can be more diverse than uniform, more lumpy than linear. Staff is committed to completing this assessment, with a report made available in mid-September. And we look forward to continuous improvement and efficiencies in collecting forecast load and resource data that can usefully be categorized, distinguished, and compiled for these purposes.

With that, I humbly invite questions and comments from those -- first from those who are here, in Hearing Room A, at the Energy Commission.

Please come to a podium, a microphone, and identify yourself?

MS. DIXON: Gena Dixon, with Southern California Edison. My question is, on the conclusions and next steps you indicated that 50 POUs had provided resource adequacy plans, how many have not, what's the total number?

MR. WOODWARD: None, they all provided.

MS. DIXON: That's -- okay, thank you.

MS. TRELEVEN: Hi, I'm Kathy Treleven --

MR. WOODWARD: Could you turn the microphone on or speak closer?

MS. TRELEVEN: How about this?

MR. WOODWARD: Great.

MS. TRELEVEN: I'm Kathy Treleven, from PG&E. And I wondered if you could tell me a little bit more about the load forecasting component of the various POU forecasts? Is the work that you presented here all from their own load forecasts; and are you seeing some of the discrepancies or the differences of opinion between the staff forecasts and the utility forecasts that we're working on with the Energy Commission, on the IOU side?

MR. WOODWARD: Yes, we did expect the load forecasts on the supply forms to match the demand data that was provided on the demand forms for the larger 15 POUs. And for the smaller POUs, they were exempt from filing any demand forecast data, so long as they provided us with the year-ahead resource adequacy data and historical data, hourly data.

So we did not have that -- that cross-check for the smaller POUs.

But where we did compare the load forecasts for the larger POUs with the Energy Commission load forecasts,

we did not see any discrepancies that are noteworthy.

MS. TRELEVEN: Thanks. And in addition, and maybe you don't know much about this, but on the utility side, or on the IOU side, in general I'd say that the C-zone forecast tends toward a lower growth rate, for example, than the utilities, for several reasons and we're working through it. Have you had a chance, yet, to look at the Energy Commission's own forecast of muni load growth and does it have any differences?

MR. WOODWARD: Just what we've presented here.

MS. TRELEVEN: Okay. Thanks very much.

MR. WOODWARD: Any other comments here, in the hearing room? If not, we can open this up to anyone on WebEx.

MS. KOROSEC: Actually, we'll start --

MR. WOODWARD: Oh, I'm sorry.

MS. KOROSEC: -- with Craig Lewis, on WebEx, since he indicated earlier he had a question.

MR. WOODWARD: Thank you.

MS. KOROSEC: Craig, your line's unmuted, if you want to ask your question.

MR. LEWIS: Yes, hi, can you hear me?

MS. KOROSEC: Yes, we can.

MR. LEWIS: Okay. My question is with respect to the renewables forecast coming online, when you look at the

forecast that the IOUs are making so much of the energy that's being contracted is dependent on very large transmission build outs, which are likely to take decades to actually be built out. And I'm wondering if the same kind of potential delays and added timeframes exist when referring to the POU-contracted renewable energy?

MR. WOODWARD: Yes, I'm sure that potential is there and that's why for the renewable energy slides we focused on the near term, through 2011, for projects that are clearly specified under contract and, in many cases, underway or under development. I think those are much less -- have much less uncertainty.

MR. LEWIS: And could you also clarify, many of the charts showed a difference between the POU -- the negative POU-eligible renewables and then TEC eligible renewables, and is that -- that was a pretty stark differential. The TEC-eligible renewables were significantly lower. In other words, the POUs were much lower percentages of renewables with respect to delivered energy than what the POUs were self-allocating, I guess is the way to say it. And I'm wondering is that partially dependent on the estimates of when transmission would be available? In other words, is this big differential dependent on transmission or what's driving those differentials?

MR. WOODWARD: No, transmission is not involved in this differential between what's called POU qualifying and Energy Commission eligible for renewable energy.

The difference is in the counter-conventions that by State law the POUs are authorized to do, and we tried to identify what those components are, you know, from large to small these are the factors of what would count as POU qualifying energy, that wouldn't count as Energy Commission eligible.

MR. LEWIS: Okay. If I could just follow with the question, my specific question that I originally typed in was regarding slide eight, which shows -- are you all still there?

MR. WOODWARD: Yes. Yes.

MR. LEWIS: Oh, sorry. Slide eight, which shows a pretty -- a pretty low growth of renewables, because it says "contracted renewables." So I'm wondering how much of that, out there in the 2010 and beyond, is likely to -- is actually likely to happen given the significant constraints on transmissions, all that that I mentioned before?

MR. WOODWARD: The key word in that question is probably likely, and there are uncertainties. I mean, there are unspecified contracts in that category, more farther out in time. And some of those probably do depend on transmission construction or a change in transmission rights

and agreements for existing transmission resources. I can't say without knowing more about specific projects.

MR. LEWIS: Is there an analysis that shows transmission constraints and dependencies that one can refer to, that analyze that a little bit deeper?

MR. WOODWARD: There may be in the RETI process. I'd refer to that, in a different proceeding.

MR. LEWIS: Great, thank you.

MS. KOROSEC: Jim Stewart, you indicate you have a question.

MR. STEWART: Hello?

MS. KOROSEC: Hello?

MR. STEWART: Hi, can you hear me now?

MS. KOROSEC: Yes, we can.

MR. STEWART: All right, very good. This is Jim Stewart from the Energy Committee of Sierra Club, California.

And I wanted to raise the question of whether any of the POUs are doing something similar to what San Diego Gas and Electric is doing in terms of utilizing the emergency back-up generators to meet peak power loads? I don't know if you're familiar, but I understand that a company called Internock has contracts with about 25 megawatts of emergency back-up generators that can be used to provide peak power for San Diego Gas and Electric.

And it seems to me that this is really a great win/win situation because we need these emergency back-up generators which, as you well know are in many cases, old diesel, dirty engines without filters. And the beautiful thing about this Internock is that they pay for the utilization -- installation of these particle filters, saving health issues, as well as then providing this back-up power at less power -- at less cost than it would cost for the utility to put in a new peaker. Are you going to -- can you -- how do we raise that into the resource planning process for all of the POUs and, of course, all of the IOUs?

MR. WOODWARD: Well, thank you for the question. I'm not familiar with that use of emergency back-up generation by San Diego. I don't know of anything similar that the POUs are using.

But I would suggest that most likely those types of emergency back-up generators are more appropriate for the distribution where key end-use loads, such as hospitals, and other key facilities, balancing area, control rooms need to have continuous electric power, and there are outages for a variety of reasons, not just supply adequacy. But in the distribution system there may be 1.4 average outages per year, but it's quite variable across the State.

But the peakers and capacity reserves we're looking at here are grid-connected and at a larger scale.

MR. STEWART: Well, in actuality, that's how they work in San Diego is that they are grid connected, and that is what -- but they're remotely controlled by the control center of Internock of which, you know, is in constant, 24/7 communication with San Diego Gas and Electric so they can bring these things on in a couple minutes.

Anyway, I guess the question I have is that who, in the CEC, is looking at this and who should I be in touch with?

MR. WOODWARD: I don't know. But please send your comments in and let us know.

MR. STEWART: All right, will do. Thanks.

MS. KOROSEC: All right, the lines are open, is there anyone else on WebEx that would like to ask a question?

Any questions?

MR. MILLER: Hello?

MS. KOROSEC: Sorry, we had the lines mixed up.

MR. MILLER: Hello, this is Tom Miller, from PG&E. Can folks hear me?

MR. WOODWARD: Yes. Hi, Tom.

MR. MILLER: Hey, hello. Jim, I want to thank you, this is a very informative presentation.

MR. WOODWARD: Thank you.

MR. MILLER: I would like to ask a couple of

questions. In your investigative work did you get any insight as to the development of energy efficiency programs and demand response programs by the POUs?

And my second question would be if the CEC has consistently done sort of regional outlooks statewide, and then the ISO, and I'm wondering if you expect to take what you learned and to give us some -- you know, and translate that into, say, more geographic and physical outlooks that the CEC may be doing?

In particular, it would be very instructive, you know, for reliability needs to understand the transfers from capacity between the balancing authorities within the State.

And so if you could comment on that, I'd appreciate it very much.

MR. WOODWARD: Two great questions, Tom, thanks. First, about energy efficiency, we had a line on the supply forms, as you probably know, for uncommitted energy efficiency, much like the categories that are well-defined for IOU procurement proceedings.

Most publicly owned utilities have built energy efficiency into their load forecast, as they presented it to us in these filings, although SMUD did have significant future year energy efficiency listings, as did LADWP. But I don't have any quantitative data to present here on that, we can do that in the report.

We did also code the data by control area, by balancing authority area, and hope to do some aggregate summaries in that respect.

The transfers between balancing authority areas is not something that, for us, is easy to identify in the resource plan filings. That's probably more -- probably the inter-tie, hourly data would be a more useful area to look at that.

But the one area that surprised me most, and kind of delightful, was the contract that the City and County of San Francisco has with PG&E for banking energy. According to the Breaker Act of the U.S. Government, 1918, San Francisco can't sell, to an investor-owned utility, the electricity from Hetch Hetchy, but it can be banked by PG&E for later distribution to the City. Because they're peaking generating capacity is often larger than their demand. And they can also transfer and sell to Modesto and Turlock, which they tend to do more often.

And in terms of balancing authority, it's not clear where their high voltage transmission is, it sort of connects to both, starting with Cal-ISO where it joins PG&Es Newark sub.

So those are good questions, but this kind of data probably doesn't get at the balancing area transfers.

But I did want to raise and allude to the

importance of reliability studies, that would still be quite useful, something that PG&E, and especially Antonio Alvarez has been championing for several years.

MR. LEWIS: This is Craig Lewis again, can I ask another question?

MR. WOODWARD: Sure.

MR. LEWIS: There's been a lot of focus on wholesale distributed generation, which is the 20 megawatts and under distribution inter-connected renewable energy generation, and the IOUs have all put applications with the CPUC for wholesale PG photovoltaic solar projects, and as an application which was recently approved by the CPUC. And then SMUD has followed with a feed-in tariff program that's aimed at five megawatts and under, all of it being wholesale PG.

And I assume that this wave of focus on wholesale PG, that's really getting around these transmission constraints, is going to catch up with the POUs pretty quickly here.

Is this something that -- is the SMUD focus on wholesale PG, is that something that was reflected in any of the data that you presented today?

MR. WOODWARD: Well, there is one component that I thought was quite interesting, where SMUD is planning to develop a central solar array near the Rancho Seco facility

and to sell shares, so that those solar facilities would be customer owned and counted as distributed generation, but the utility would retain the renewable energy attributes for counting purposes. And yet, that would be customer owned distributed generation.

That's one of those areas where it's hard to -- when we're writing forms and instructions, to create or find definitions that are clear and compelling across all sorts of load-serving entities and other jurisdictions.

MR. LEWIS: Yes. Well, SMUD recently announced, it was just within the last two or three weeks, announced a 100-megawatt feed-in tariff program that they expect to fulfill 100 megawatts in the order of one to two years, is my understand.

So maybe you haven't seen that announcement, but it's a --

MR. WOODWARD: No, I haven't, sir. Thank you.

MS. KOROSEC: Is there anyone else online with a question?

MR. WOODWARD: Wonderful. Thank you all for listening, those of you on WebEx.

And now, if we have Valerie Puffer online, I'd like to introduce Valerie, from Glendale Water and Power, for a different perspective.

MS. PUFFER: Okay, hi. Can everybody hear me?

MR. WOODWARD: Yes, we can, thank you.

MS. PUFFER: Okay, hi. As Jim mentioned, I'm Valerie Puffer, I'm the Power Systems Analyst at Glendale Water and Power. Thank you very much for allowing me to make comments today on behalf of the City of Glendale.

I also wanted to tell you, while you're here and everyone was around, I wanted to thank the CEC staff for helping us -- kindly assisting us in deciphering the regulations in order to meet our filings as well. You guys have been very helpful.

Let's see, Glendale's a publicly owned utility. We have definitely a commitment to our customer/owners to provide reliable power -- reliable power and water at reasonable rates. We have a diverse portfolio of resources. We've got coal, natural gas, landfill gas, wind, geothermal, and hydroelectric. And we are continuing our efforts to procuring renewable resources.

Glendale is located in Southern California. We provide service for over 83,000 electric and 33,000 water customers.

Our peak for 2008 was, as you mentioned, about 306 megawatts. We reached 336 in 2006.

Glendale's customers are mostly residential, but about a third of our power consumption is from large commercial.

So in looking at the resource adequacy and electric resource plans, I wanted to make a few comments for the CEC to consider; is to keep flexibility in regulations when dealing with the POUs; consider that our local generation is definitely needed for reliability and stability of our whole system.

The plant does help meet our planning reserve obligations.

You mentioned on slide 15 that the PTUC jurisdictional PUCs can only count biomass combustion as renewable energy if the facility does not use fossil fuel. This is important to POUs to keep dual fuel facilities; this is our natural gas and landfill gas units as eligible for RES renewable requirements.

Also consider, when making regulations and requirements for POUs and larger utilities, also, is the rate impacts and staffing to meet those regulations. It's becoming a problem to constantly report a lot of very detailed information that is required to come out of our offices, we don't have a lot of staff to do that.

Continue to work on streamlining the reporting requirements, work with FERC, WECC, and CIA to allow reporting of the same information one time only, and not multiple times.

And again, those are my comments, thank you very

much.

MR. WOODWARD: Thank you, Valerie. And again, I thank you for working with us over this several months on the correcting our understandings and getting the data right on the supply plan.

I've often thought of the POU resource planning staff as sort of our unpaid consultants in this project.

MS. PUFFER: Thanks.

MR. WOODWARD: Are there any questions on WebEx or from those of us here in the room from Glendale, for Valerie Puffer?

You did make a comment about trying to minimize the duplicate filing requirements and we hear that loud and clear, and take that very seriously. We did look this time to allowing an alternate filing format, using the WECC formats that balancing areas provide to the WECC, and we did get two filings from Redding and Burbank that way, that are in some ways more detailed.

But what those filings didn't have was the S-5 forms for bilateral contracts and they didn't identify what counts as renewable energy or collect the data on retail sales. It was more of the strict engineering and electricity, and capacity needs.

MS. PUFFER: Right.

MR. WOODWARD: So we did have to -- pardon me?

MS. PUFFER: The greenhouse gas report requirements are very detailed and they might -- what we send to the Air Quality Resource Board, they might actually meet the needs because they are very detailed.

MR. WOODWARD: Very good. And I would humbly point out that in many ways we're collecting data at the 10,000 foot level for the big picture of trends. The data we're presenting here is not for auditing or verification purposes, we didn't ask for settlement quality data, which is often difficult for some utilities to acquire from different departments and the timeframes involved.

MS. PUFFER: Correct.

MR. WOODWARD: Thank you, Valerie.

MS. PUFFER: Thank you.

MR. WOODWARD: And now I'm very happy to introduce Brad Parker, from the Los Angeles Department of Water and Power, and we're glad to have him here today.

MR. PACKER: Thank you very much, Jim.

I'd like to say that my name's Brad Packer.

MR. WOODWARD: Brad Packer, I'm so sorry, I knew that.

MR. PACKER: And I have a nametag right here that you guys made for me. Thank you very much for doing that.

I work at the Department of Water and Power for the City of Los Angeles. My responsibilities there are to

manage our Wholesale Energy Resource Management area, or sometimes known as wholesale marketing, it's been known in the past as bulk power.

Our responsibilities in this section is to make sure that DWP always has sufficient energy and capacity to meet its customers' demand, and that's what we do on a day-by-day basis.

I appreciate the opportunity to be able to come out here and take a look at your presentation that you've made today, and I hope that I can make a couple of comments that will both enhance and clarify it.

But like I say, we are very happy to participate and we appreciate this opportunity.

I wanted to know if I could take a look at some of your slides and make some comments on them, and perhaps we could take a look at slide number 6 to begin with?

And this is the slide that has POU capacity addition since 2004, and you did go ahead and mention one of our Haynes combined cycle repowerings that we did.

We also have a variety of other additions that we have made over this timeframe, and as I went ahead and counted them up, we actually have ten new projects. The majority of those new projects are renewable. And these projects add up to an increase in capacity of 534 megawatts overall, and of those 361 megawatts are renewable projects.

Also during this timeframe we retired some units, and this had to do with the Mojave Coal Generating Station, of which DWP owned a 270-megawatt share. And that happened at the end of 2005. So we did go ahead and reduce our capacity by 270 megawatts.

And as we go to the next slide, which is slide number 7, this talks about the planned POU capacity additions, mostly renewable.

And I guess my comment is, again, I want to go ahead and tell a little bit about some of the projects that we do have both planned and that are coming online in 2009 and 2010.

We have 11 new projects. And if you would have put those all on this slide of course there wouldn't be room for everyone else and that wouldn't be fair to everyone else.

But we do have over 1,000 megawatts of projects planned and there's, like I said, 11 new projects. Exactly, it's 1,116. And these have -- these are quite a few wind projects, but we also have some solar projects coming on in this timeframe.

The next slide I wanted to address is slide number 13. And in this slide, and also slide number 14 and 15, and we had one of the questions asked regarding this, and I'm going to bounce around between these three slides. So if we

take a look at the next slide, which is 14, and this slide shows the difference between what the California Energy Commission considers as qualifying and what the POUs consider as qualifying.

And this one, you know, it puts the POUs in, I would say, maybe a little bit of a poor light by saying, well, it looks like you guys are counting renewable resources that we don't consider qualifying.

And I wanted to talk a little bit about specifically DWP and the differences between what are qualifying for both of our utilities, for ours and for the CEC.

And there's six particular facilities that DWP counts as qualifying, that the CEC does not consider, and I'd like to just describe these just for a moment. And you had actually described some of them, also.

The first one, the first three, actually, are along our aqueduct system and they are our Gorge plants. As everyone knows, the 30-megawatt and below is considered small hydro. We have these three units and they're rated at 37 megawatts, so which is very close to 30.

You did also talk about our large hydro, and so DWP counts large hydro as actual large facilities, and these are the Hoover facility, which we have almost 500 megawatts of capacity out of that plant, and then our pumped storage

in Castaic, which you also mentioned, Jim, and that's about a 1,200-megawatt.

So on those scales of between small and large, those three Gorge units, at 37 megawatts, we do count as small.

The next two facilities are also along our aqueduct system and they're Power Plant One and Power Plant Two. Power Plant One has four units, the largest being 27 megawatts, and that plant sums to 76.

So all of the units in there are under 30 megawatts, however, since they're within the same building the CEC will classify that as a facility and, therefore, be a large hydro.

The second one is the Power Plant Two. That has three units and they're rated at 18 megawatts each, for a total of 42. And again, for the same reason, we count those individually as small hydro.

And then the number six, the sixth one that is a difference here and that, again, you had referred to, is our -- the agreement that the Department of Water and Power has with the City of Los Angeles at our Scattergood Generating Station.

And the Scattergood Generating Station sits next door to the Hyperion Sewage Treatment Plant, and in 1985 DWP made an arrangement that they would go -- that the sewage

treatment plant was having difficulty in dealing with the digester gases associated with the sewage treatment process, and so DWP said, well, we have our units just right next door, we'll go ahead and burn that gas in our Scattergood facility.

And so we, DWP counts the renewable digester gas portion of that generation as renewable.

We do plan, within about four years, to go ahead and have a separate facility at the Hyperion Sewage Treatment Plant to go ahead and put in new generators, and you'd also talked about that.

And so for us, as we see right now, we're burning that digester gas and counting it, but CEC says, well, you can't really count that until you go ahead and burn it on site.

So those are just some subtle differences of the way that DWP takes a look at the renewables.

Other than that, all of our renewables are counted in the same manner as the CEC.

Also, back on slide number 13 -- thank you. I want to talk a little bit about the Department of Water and Power's renewable portfolio standard and their goals.

In 2003, it was the first year we began measuring our renewables and we had three percent. And in 2008, our power content label shows that we have eight percent.

And in this slide it shows that we have 5.5 percent. And those differences between the 5.5 and the eight percent are what I just talked about with our six facilities which are close to CEC qualifying.

DWP takes very seriously the goals and, again, the regulations regarding meeting a 20 percent in 2010, which is next year.

And we have, on this slide, a 35 percent goal by 2020, and that was accurate up to about a month ago, when the Mayor of Los Angeles, Mayor Villaraigosa, announced that our new goal was going to be 40 percent by 2020.

So I just wanted to go ahead and provide those clarifying comments on that slide.

And you had showed, Jim, on slide number 15, the biomass in the LADWP, and I think I provided an explanation of those.

I wanted to end up on your last slide, slide number 25, and DWP has heard that there are some perceptions in California that DWP will go ahead and purchase RECs in order to meet our RPS goals, and that’s not correct with us, and I wanted to go ahead and just read a sentence from our renewable portfolio standard, which is our official statement.

And it says that; “the LADWP will not purchase the renewable energy credit from a renewable resource without

purchasing the associated energy."

And so we want to be very straight forward with what we present as renewable energy, and that actual energy that goes to our customers.

And just lastly, to close up here, I just again want to say thank you for giving me this opportunity. I did make an arrangement with Jim, after this meeting, to go ahead and provide additional information that will go ahead and clarify what some of our goals are, and clarify which plants and renewable energy projects that we are pursuing, and hope to establish a very close working relationship with the CEC and the work that LADWP is doing.

Thank you very much.

MR. WOODWARD: Thank you, Brad. We appreciate your comments and the information very much, and look forward to a continued information exchange.

Like the projects, we have no problem dedicating a table just for LADWP's projects, if that's appropriate. I mean, we might be able to get them all on one page for renewable projects.

All right, I did want to clarify for those who may be listening, that in using the terms "Energy Commission eligible" and "POU qualifying" I was just using the terms as they were developed in the KEMA Consulting report, published December 2008. I was not trying to say that it shouldn't

count or I was just trying to identify the differences since there's often some confusion among POUs and IOUs about what those differences in counting conventions are. And they can change over time, as they have for all -- several categories of LSEs.

So thank you very much for those comments.

Does anyone here have questions or comments for Brad Packer?

Or on WebEx?

MR. MILLER: Can I ask a question of Brad?

MR. WOODWARD: Yes, go ahead.

MR. MILLER: Can folks hear me?

MR. WOODWARD: Yes. Could you identify yourself?

MR. MILLER: Sure. This is Tom Miller, with PG&E. And I would, if it's okay, I'd like to ask Brad or Jim, and you may have spoke to this earlier, Jim, and I may have missed it, but my question is regarding the -- sort of the counting of the intermittent type renewable resources towards meeting your capacity requirements, and getting some -- what I'm asking for is some insights as to if there's a methodology, or the -- you know, discounting towards a dependable capacity from the installed?

MR. PACKER: I'll go ahead and start this, and I think Jim mentioned this a little bit in his presentation. DWP will take a look for -- and this is particularly

regarding wind facilities.

DWP has reviewed over 20 studies that have been done over the last 10 to 15 years of defining what dependable capacity of a wind facility is. We know that for a lot of wind facilities that the capacity factor of the energy generated is usually about 30 percent, sometimes 32, 33 percent, sometimes a little bit below 30 percent.

And, however, that doesn't mean that when a utility is experiencing its peak demand during the day that we will get 30 percent of the capacity out of that wind facility.

At this point DWP, which has gotten a lot of its guidance from these studies, is now counting ten percent of its installed capacity.

I think, Jim, you had mentioned our Pine Tree Farm is rated at 120 megawatts. We're currently counting ten megawatts of that as -- or excuse me, 12 megawatts of that, which is ten percent, as dependable capacity.

What we are doing, though, as we get more information and getting more history from the wind plants that we do have ownership in, is we will be making adjustments as we get more information.

But as we begin our relationships with the wind farms that we're starting a little bit conservative, and as we get more information we may go ahead and change that.

MR. WOODWARD: Thank you, Brad.

This is Jim Woodward. I would add to that, just from other utility filings, Redding did not have a discount for their wind energy because they had a shaping and firming contract on top of that, so it made good use of transmission resources, as well as helping Redding meet its firm peak loads, which of their low capacity factors in Redding, high air conditioning loads in the summer. So that's one method, by using firming and shaping contracts to integrate renewables with the help of all the utilities outside California.

SMUD takes wind energy from facilities that are actually in Cal-ISO and export it to the SMUD Western Control area, since the Solano wind farm is west of river, west of the Sacramento River. And as SMUD intends for that facility to grow, providing more energy, they see a value in adding the pumped storage facility at Iowa Hill, 390 megawatts, to better integrate the wind.

Because on the hot -- the hottest of summer days here, in Sacramento, it's sometimes dead calm. But when there is such a high temperature we develop a heat low and, fortunately, many days we'll get a Delta breeze that will eventually cool things off at night.

But there's just enough difference in time between when the Delta breeze reaches the Solano wind farm and when

the peak loads hit the Sacramento Metropolitan area, that SMUD sees a value in being able to store that energy from one peak generating period to the next day's peak load.

MR. PACKER: And, Tom, this is Brad Packer again, I'd like to add one more comment.

We usually talk about the dependable capacity of the wind, however, we also are having a lot of investment in new solar facilities. And the studies that we have done show that as you take a look at the output of a typical photovoltaic facility and overlay that with a demand curve of our utility, we'll note that the solar facility peaks between two and three hours prior to the peak of our demand.

And we are currently doing studies to find out how much of that solar facility will be available during our peak, and those studies are ongoing.

MR. MILLER: Thank you, Brad and Jim, both, that's very helpful. And it's good to know that the POUs are kind of wrestling with the innovation issues, as well.

And I'm going to put on my, the WECC hat right now, I work -- I chair a working group there, and I just want sort of a heads up, there are some really, in my view, some very good work going on at WECC under a variable generation subcommittee, headed by Brad Nichols, that is working on a lot of these issues. You know, globally, you know, states to the west. And I just wanted to mention that

because I think it's a good forum for both the CEC and POUs to follow, too.

So thank you, again, for the explanation, it makes sense to me what you're saying. Thanks.

MR. WOODWARD: Very good, Tom.

Do we have other questions or comments on the WebEx?

Well, if not, I thank you again for listening and participating, especially thanks to Valerie Puffer, at Glendale, and Brad Packer, here from Los Angeles Department of Water and Power.

We look forward to other comments, formal and informal, as listeners and participants may wish. And we look forward to having this report done very soon. And there are many other activities, workshops, and proceedings still ahead for the 2009 Integrated Energy Policy Report, of which this is just a part.

And with that, we'll conclude today's staff workshop. Thank you.

(Whereupon, at 10:44 a.m., the Staff Workshop was adjourned.)

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