Documents Filed in Support of Legislature Record
for
Assembly Constitutional Amendment No. 11

California Legislature 2015-2016 Regular Session
Assembly Committee on Utilities and Commerce

VOLUME I

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1. CPUC Public Record Act OIR Workshop Report and evidence
2. Loss of Songs Filings
3. Complexity and Secrecy Paper
4. Haas School Report
5. Petition Requesting Aliso OII
6. Malfeasance Report
7. Coastal Commission Complaint
8. Decision on OII in San Diego Fire Case
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EXHIBIT 1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Improve Public Access to Public Records Pursuant to the California Public Records Act.	R. 14-11-001 (Filed November 6, 2014)

IMPERIAL IRRIGATION DISTRICT'S REPORT ON THE CPUC'S HISTORY RELATING TO ACCESS TO PUBLIC RECORDS AND COMMENTS FOLLOWING WORKSHOP

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Following a Workshop hosted by the Public Utilities Commission, and thereafter an "Energy Group" meeting at the offices of Southern California Gas in Los Angeles in which counsel for Imperial Irrigation District was in attendance, the Imperial Irrigation District (IID) submits the following report and recommendation of procedures to be adopted by the California Public Utilities Commission ("CPUC").

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I. PUBLIC RECORD AT THE CPUC

In 1968, the legislature issued this directive to the CPUC: "The following state ** bodies shall establish written guidelines for accessibility of records ** Public Utilities Commission (CPUC)." Govt. Code § 6253.4(a). The CPUC guidelines "shall be consistent" with all other Public Records Act (PRA) sections and "shall reflect the intention of the Legislature to make the records accessible to the public. " Govt. Code § 6253.4 (b).

Forty-eight years later, in November 2014, the CPUC issued an Order Instituting Rulemaking (OIR) for the PRA in which the CPUC admitted its existing record access order (General Order 66-C) adopted in 1972 "**does not articulate the process and procedure for obtaining Commission records**." In the OIR, the CPUC admitted General Order 66-C "identifies several exemptions from public disclosure that are inconsistent with the [C]PRA. In its Order Instituting Rulemaking, the CPUC announced its intent "to address improving the public's access to records that are not exempt under the California Public Records Act or other state or federal law." R.14-11-001, p. 1.

The CPUC's PRA practice has been to withhold records from the public in systematic violation of the PRA. The CPUC claims its decision to withhold records under claimed PRA exemptions is not subject to the "in camera" review required under the PRA. However, when public records appear to be improperly withheld from a member of the public, a Superior Court is authorized to order the records produced if the Court determines the records are not exempt after conducting a review of the records.

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Govt Code § 6259 provides:

> (a) Whenever it is made to appear by verified petition to the superior court of the county where the records or some part thereof are situated that certain public records are being improperly withheld from a member of the public, the court shall order the officer or person charged with withholding the records to disclose the public record or show cause why he or she should not do so. The court shall decide the case after examining the record in camera, if permitted by subdivision (b) of Section 915 of the Evidence Code, papers filed by the parties and any oral argument and additional evidence as the court may allow.

As late as November 2014, the CPUC contended Section 6259(a) does not apply to the CPUC because Public Utility Code § 1759 does not allow the Superior Courts to review the CPUC's regulatory decisions. The CPUC contends CPUC decisions to withhold claimed public records can only be reviewed by appellate courts under Public Utilities Code § 1757. The practical effect of the CPUC's contention is to remove even an in camera review of the withheld records to determine if the exemption is well taken. This position to narrowly and not broadly construe the Public Records Act requirements has significant impact on the ability to obtain records in matters in which the public bears significant costs. For example, in the San Onofre test case discussed below, the CPUC is withholding 124 records related to a closed nuclear plant for which the CPUC is requiring the public to pay over $3.3 billion in lost profits and costs.

The CPUC has not used its authority to allow for "greater access to records than prescribed by the [PRA's] minimum standards." Govt. Code § 6253(e). Further, the CPUC in practice has ignored the rule that CPUC-held information is presumed to be public information 2006 Cal. PUC LEXIS 222, *8-9. The party producing information used to make CPUC decisions is supposed to bear a strong burden of proof for the CPUC to grant confidential treatment. 2006 Cal. PUC

LEXIS 222, *8-9. Instead of reading legal authority broadly to expand access to CPUC records, the CPUC practice is to read exemptions broadly to restrict access. See Art I, Sec 3 Cal State Const. (authority shall be broadly construed if it furthers the people's right of access, and narrowly construed if it limits the right of access)

The CPUC has adopted the practice of reading Pub. Util. Code § 583, which empowers the CPUC to release documents filed by utilities with the CPUC, to say such documents cannot be released. Pub. Util. Code § 583. Instead, the CPUC has allowed a provision protecting confidentiality of "market sensitive [procurement] information" to provide blanket secrecy for documents that have no material impact on a procuring party's market price for electricity. 2006 Cal. PUC LEXIS 222, *10-12.

The CPUC Commissioners are systematically denying the people's "right of access to information concerning the conduct of the people's business [at the CPUC]." Cal. State Const. Art I, Sec 3. The meetings at which CPUC decisions are made and the writings of the CPUC public officials making them are not "open to public scrutiny;" accordingly, they are in violation of the State Constitution. See, Art I, Sec 3 (b)(1).

The CPUC does not construe the PRA, Commission orders, rules or authority broadly if they further the people's right of access, and narrowly if they limit the right of access. Its approach is in violation of Art I, Sec 3(b)(1) of the California State Constitution.

II. INVESTOR-OWNED UTILITIES DOMINATE THE CPUC

The stock exchange traded electric and gas utilities have taken over the government of the State, as Governor Hiram Johnson warned 100 years ago. Instead of "regulation of the [utilities], as the framers of the new Constitution fondly hoped, the [utilities have] regulated the State." The takeover was made possible by the California Public Utilities Commission's (CPUC) wholesale disregard of the public records act.

III. STOCK EXCHANGE UTILITIES HEAVILY CAPITALIZED

The three stock exchange traded companies -- San Diego Gas & Electric (SDG&E), Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) -- dominate the CPUC; they have a combined market capitalization of $66,000,000,000:

Utility	Shares	Market Value
SDG&E	249,215,763	$24,500,000,000
Edison (SCE)	325,811,206	$18,100,000,000
PG&E	492,830,471	$23,628,000,000
	1,067,857,440	**$66,228,000,000**

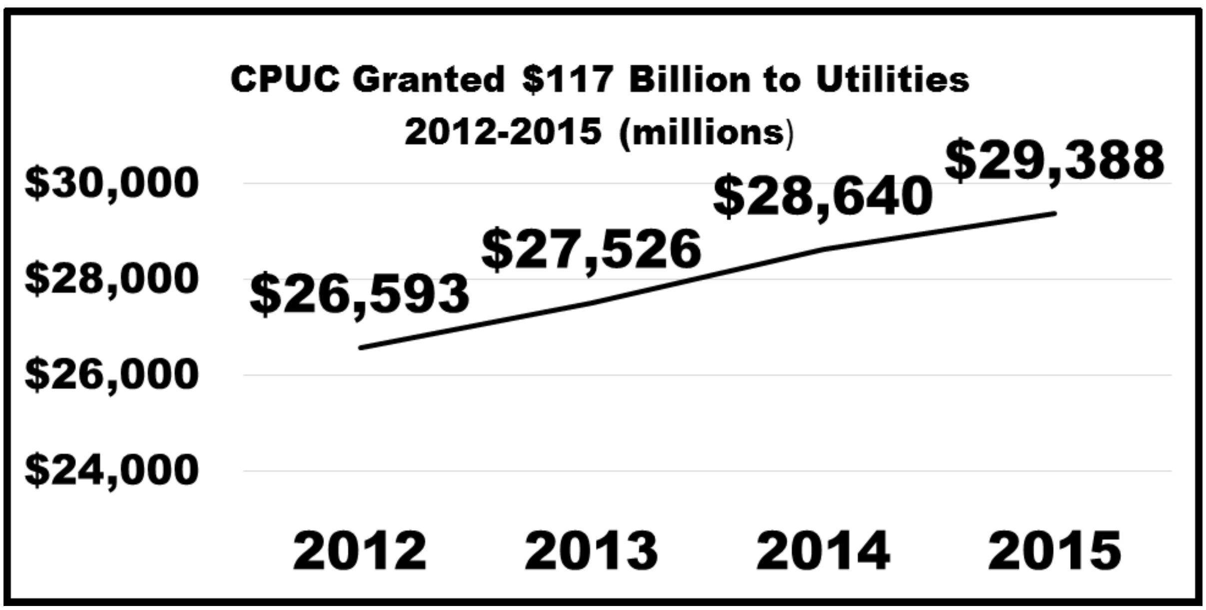
More than 300,000 investors own over 1,067,857,440 shares in the three utilities (an average of 3,559 shares): 249,215,763 (Sempra, for SDG&E), 325,811,206 (SCE) and 492,830,471 (PG&E). SCE has the fewest shareholders, and Sempra the most:

Year	SCE	PG&E	Sempra	Total
2012	45,430	71,943	245,000	364,385
2013	41,000	67,982	230,000	340,995
2014	41,000	64972	205,000	312,986
2015	41,000	61,989	195,000	300,004
2016	35,375	59,317	175,000	271,708

The three utilities have over 22,000,000 customers, with PG&E having the most customers and SCE the fewest:

Utility	Meters/Accounts
PGE	9,700,000
Sempra	7,300,000
SCE	5,200,000
	22,200,000

The CPUC allowed the three investor-owned utilities to charge their customers over $117,000,000,000 since 2012:



From this cash flow, the three investor-owned utilities paid out over $7.5 billion in dividends since 2012:

Year	2015	2014	2013	2012	
SCE	$544	$463	$486	$424	
Sempra	$628	$598	$606	$550	
PG&E	$856	$828	$782	$746	
Total (in millions)	**$2,038**	**$1,889**	**$1,874**	**$1,720**	**Total $7,521**

SCE (Edison) and Sempra both reported recent increases in their dividends. In December 2015, SCE (Edison) declared a 15% increase to the annual dividend rate from $1.67 per share to $1.92 per share. In February 2016, Sempra approved an 8% increase in its dividend.

Four of the 300,000 investors (T. Rowe Price, State Street Corp., Franklin, and Vanguard) collectively hold stock in the three companies (Sempra, SCE and PG&E) with a total market value exceeding $16,000,000,000:

Shareholder	Sempra	SCE	PG&E	Total
Price (T.Rowe)	$2,377,813,321	$795,907,023	$2,377,813,321	$5,551,533,665
Vanguard	$1,561,511,406	$1,273,983,121	$1,561,511,406	$4,397,005,933
State Street Corp	$1,218,462,188	$1,492,391,695	$1,218,462,188	$3,929,316,071
Franklin Resources	$783,021,903	$370,703,738	$1,443,271,634	$2,596,997,275
			Total	**$16,474,852,944**

Representatives from these four companies and others were in constant contact with CPUC Commissioners. Two examples, one from 29 February 2012 and the other from 10 September 2012, had the following seeking an audience with the Commissioners in San Francisco:

29 Feb 2012		10 September 2012	
Charlie Hebbard	(Fidelity)	Brian Chin, Amit Marwaha	Citi Investment Research
Matt Litwin	Blackrock	John Kohli	Franklin
Leslie Rich	JP Morgan	Eric Fogarty	Goldman Sachs Asset Management
Ryan Burgess	**T** Rowe Price	Matt Fallon	Talon Capital

IV. A "GREAT PROFUSION DAILY"

On 6 June 2014, CPUC Commissioner/now-President Picker expressed his "deep gratitude" to Wall Street analyst Julien Dumoulin-Smith "whose many research products reach my inbox in great profusion daily." Those many research products were a fraction of the ones Wall Street utility investor interests regularly send to Commissioners. A review of a sample of 7,500 such communications shows Wall Street utility investor interests shapes the body of knowledge used by commissioners make utility decisions affecting the public.

Wall Street flows information to Commissioners in a number of ways, in addition to emails:

(1) Commissioners meet in secret in New York with Wall Street players to discuss pending regulatory matters;

(2) Wall Street players meet in secret in San Francisco with CPUC Commissioners to discuss pending regulatory matters;

(3) Wall Street analysts, investment bankers, and utility investors direct a constant flow of ex parte investment information to CPUC Commissioners regarding matters pending before the CPUC; and

(4) the utilities fund free travel to foreign countries for Commissioners where utility executives and CPUC Commissioners decide, in secret, issues pending before the Commission.

In September 2012, former CPUC Commissioner Mark Ferron asked for the research from Wall Street as a quid pro quo for agreeing to meet with Morgan Stanley bankers:

> While I enjoy meeting with equity analysts and investors, **I have only one stipulation before agreeing to a meeting: that I am put on the distribution list for research pertaining to California utilities**. Is

this something that you are able to agree to? If so, could you also please send me any recent research (say over the last 6-12 months) on the sector that you think might be relevant?

A. Peevey-New York

Former CPUC Commissioner Michael Peevey's emails and calendar show Peevey regularly visited key Wall Street players while he served as CPUC President. On 12 March 2012, Credit Suisse Vice President Gavin H. Wolfe wrote that Peevey would be "flying into NY in the afternoon, doing a sellside analyst dinner, then the next morning a big open investor breakfast presentation, and then a run around the city seeing the big CA utility investors." Wolfe continued: "I will likely be with you [Peevey] the entire trip as would Don Eggers, our research analyst. I will call you to discuss and other matters. Best G"

Peevey assisted Picker, his replacement as CPUC President, to gain access to Peevey's Wall Street connections. In May 2014, Peevey asked Bank of America investment banker Gavin Wolfe to help Picker "**to get a read on the investment community view of California regulation."** Peevey asked Wolfe to set up "a luncheon or other meeting with him and several of your colleagues, not only from BofA, but other investment houses."

Wall Street favored Peevey's lax attitude toward enforcing the CPUC regulations against offending utility executives. Their sentiment is documented in a consumer research blog: [1]

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[1] http://smartmeterharm.org/2016/01/05/more-email-revelations-jp-morgan-deutsche-bank-citigroup-boa-and-ubs-oppose-cpuc-reform-want-continued-supportive-agency/

- Steve Fleishman, Bank of America/Merrill Lynch Bank:
  Viewed Michael Peevey remaining as CPUC President "as key given the consistent influence Peevey has provided the Commission"
- Jonathan Arnold, Deutsche Bank:
  Hoped there'd be "no major change in the regulatory tone and direction"
- Jim von Riesemann, UBS:
  "We hope the new CPUC will continue to equitably balance consumer and shareholder interests; we believe Chairman Peevey has done just that and has been a stabilizing balance on the commission."
- J. P. Morgan report:
  - "[W]e anticipate that more consumer-friendly policies could be detrimental for the California utilities, and could impair their ability to recover the significant capital investments that the utilities are looking to make in the next several years."
  - "Fear of a more consumer-friendly CPUC may well be realized. It was not clear to us that California Governor Jerry Brown was going to go down the path of appointing a less supportive Commission…"
  - "We caution that [Michael Peevey's] potential departure from the PUC would create additional turnover and could allow for an even greater shift in California's overall regulatory framework. This, in our view, would be perceived as a negative by the market. Recall that Peevey has extensive experience in the utility industry, which many observers had perceived as quintessential for his reasonable and even-keeled stewardship of the Commission."
  - "[W]e had previously assigned premium valuation to PCG shares on supportive regulation in CA."

B. Picker-New York

Bank of America's Wolfe accommodated Peevey's request, and by 12 May 2014, directed Brian Chin (also at Bank of America) to offer investor meetings for Commissioner Picker: "Based on our prior conversation, for Monday June 23 and/or Tuesday June 24, I recommend the following options for meetings with investors." The options offered included "One Large Venue" or "Half day of 1x1 meetings + Venue" or "Full day of 1x1 meetings + intimate group meeting." Wolfe reminded Picker "President Peevey thought it might make more sense to have Mike (Picker) meet with the broader research and investor community." Wolfe suggested that Bank of America Investment "organize a Wall Street Research and Investor Luncheon" for Picker in New York. On 23 May 2014, Bank of America's Brian Chin was told Picker had "chosen the last option, the 'full day of 1x1 meetings + intimate group meeting." Picker set his Wall Street insider meetings for the 23rd and 24th of June 2014.

On those two days in June 2014, Picker went on the Bank of America roadshow with more than 20 Wall Street kingpins:

Bank of America
Merrill Lynch

Roadshow Schedule
CMR Picker
Monday, June 23, 2014

C. Wall Street to San Francisco and Beyond

While Picker and Peevey paid visits to Wall Street, Wall Street players returned the favor with regular visits to Peevey, Picker and other Commissioners in San Francisco. A 31 October 2013 email from CitiBank's Sophie Karp to Michael Peevey is a typical example. Ms. Karp told Peevey she was on Shar Pourreze's North American Power group team, and said CitiBank was planning "our 2014 annual investors' trip to California" with 15-20 representatives of large institutional investors who will be accompanied by two Citi analysts." Karp told Peevey CitiBank's "priority to meet with Commissioners and their advisors as our clients are extremely focused on the regulatory environment in the state." Karp told Peevey his group "currently [have] meetings with Commissioners Peterman, Ferron and Florio (advisors) on January 15 at 10am, 11am, and 1:30pm."

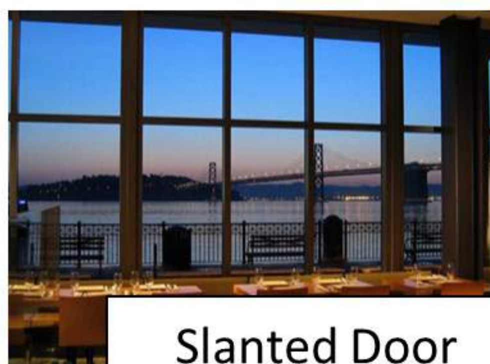
CitiBank was not unique in organizing private meetings with Commissioners in San Francisco. UBS, Bank of America, and many other Wall

Street players were granted insider access to CPUC Commissioners there. In some cases, Wall Street bankers met Commissioners in other cities. For example, after Picker's June 23 and 24, 2014 meetings, Bank of America continued its road show in New York. UBS's Julien Dumoulin-Smith met with Peevey in Sacramento on 11 August 2014.

D. <u>Wall Street Wines and Dines Commissioners</u>

Commissioners also meet with Wall Street executives over dinner at expensive restaurants. For example, Gavin Wolfe, the Wall Street insider Peevey asked to help set up Picker's 23 and 24 June 2014 New York meetings with Wall Streeters, made a dinner date with Peevey in San Francisco in October 2013. Wolfe told Peevey Ray Wood, Bank of America's head of Power & Renewables, would be joining the dinner party. Wolfe and Peevey opted in favor of the Slanted Door over the Kokkari Restaurant:

Kokkari



Slanted Door

E. <u>CFEE-Domestic and Foreign Junkets</u>

The utilities carry their message and receive the inside information they seek during junkets sponsored by the utility-funded California Foundation for the Environment and the Economy (CFEE). There, they provide private accommodations for CPUC Commissioners and utility executives to conduct CPUC business outside public scrutiny. These sessions are held for the ostensible purpose of discussing general issues, but in many instances, serve as nothing more as pretexts for collusive decision making. Here is a list of the CEFE "conferences" since 2007:

CONFERENCE TITLE	DATE OF EVENT	CONFERENCE LOCATION
Roundtable Conference on Water Restructure: The Path Toward a Drought-Resilient California	Nov 19-20, 2015	Omni La Costa Conference Center, Carlsbad
Roundtable Conference on California's Transportation Infrastructure *Attacking the Transportation Infrastructure Funding Gap: Do we have the weapons?*	Apr 30-May 1, 2015	Silverado Conference Center, Napa
Roundtable Conference on Information and Communications Technologies (ICT): Technological Advances and Social Expectations	March 5-6, 2015	The Lodge at Sonoma
Electrifying Transportation Workshop	October 7-8, 2014	Cavallo Point Conference Center, Sausalito
Roundtable Conference on California Water and the Drought - Challenges, Actions, and Pragmatic Lessons from Other Nations	Sept 29-30, 2014	Meritage Conference Center, Napa
Roundtable Conference on California's Transportation Infrastructure: How Do We Get to Success?	May 15-16, 2014	The Lodge at Sonoma
Information and Communications Technologies (ICT) Infrastructure for an Advancing Economy and Future Jobs	February 27-28, 2014	Meritage Hotel Conference Center, Napa
Achieving California's Energy and Climate Goals Evolution or Revolution?	December 9-10, 2013	Cavallo Point Conference Center, Sausalito

CONFERENCE TITLE	DATE OF EVENT	CONFERENCE LOCATION
Roundtable Conference on Local Water Supply and Quality: Doing More With Less	October 29-30, 2013	La Quinta Conference Center, La Quinta
Energy Workshop - Rate Design for a 21st Century Electricity System: How does it all add up?	March 6, 2012	Harvest Inn, St. Helena
Roundtable Conference on Information & Communications Technology (ICT)	February 23-24, 2012	Carneros Inn, Napa
Advanced Communications Roundtable Conference: Making Sense of Today's Converging Information and Communications Technologies (ICT) Eco-system	March 17-18, 2011	The Lodge at Sonoma
Energy Roundtable Summit on Distributed Generation	December 8-9, 2011	Cavallo Point Conference Center, Sausalito
Roundtable Conference on California's Infrastructure — A Path to Economic Recovery and Jobs	October 10-11, 2011	Terranea Conference Center, Palos Verdes
Strategies for Water Supply Reliability and Sustainability: "What is the Long-Term Solution?"	March 3-4, 2011	The Lodge at Sonoma
Navigating the Changing Landscape: IP, Broadband, and the Wireless Revolution	April 29-30, 2010	Silverado Conference Center, Napa
Roundtable Conference on Building Partners to Finance and Deliver Infrastructure Projects in California	March 4-5, 2010	Silverado Conference Center, Napa
Roundtable Conference on California's Clean and Reliable Energy Goals: Getting to 2020 – A Reality Check	December 9-10, 2010	Carneros Inn, Napa

CONFERENCE TITLE	DATE OF EVENT	CONFERENCE LOCATION
Roundtable Conference on Goods Movement	May 20-21, 2010	The Lodge at Sonoma
Roundtable Workshop on Ensuring Reliability and Sustainability for California's Water Supply: "Putting Your Own Oxygen Mask on First"	October 4-5, 2010	Silverado Conference Center, Napa
Infrastructure Financing and Project Delivery Conference	March 12-13, 2009	Silverado Conference Center, Napa
Roundtable Conference on California's Clean and Reliable Energy Goals: How Do We Develop the Infrastructure to Achieve Them?	December 7-8, 2009	Cavallo Point, Sausalito
Roundtable Conference on California's Water Supply and Infrastructure	October 8-9, 2009	The Lodge at Sonoma
Roundtable Conference on Goods Movement	April 23-24, 2009	Renaissance Hotel, Long Beach
Roundtable Conference on Information & Communication Technologies (ICT), Practical Applications and Policy Environment	June 18-19, 2009	Silverado Conference Center, Napa
Roundtable Conference on Transportation Fuels	May 7-8, 2009	The Lodge at Sonoma
Roundtable Conference on Telecommunications and Advanced Communications Technologies	May 29-30, 2008	Silverado Conference Center, Napa
Roundtable Conference on California's Water Supply: The "Big Fix," Interim Solutions and How We Get There	Oct 5-7, 2008	Ojai Valley Inn, Ojai
Roundtable Conference on Energy & Environmental Initiatives	December 11-12, 2008	Ritz-Carlton Conference Center,

CONFERENCE TITLE	DATE OF EVENT	CONFERENCE LOCATION
		Half Moon Bay
Roundtable Conference on Infrastructure	Jan 24-25, 2008	The Lodge at Sonoma
Roundtable Conference on Natural Gas and Integration of Renewable Energy "The Blue Bridge to a Green Future"	April 17-18, 2008	Silverado Conference Center, Napa
Conference on Implementation of AB32 - The CA Greenhouse Gas Initiative	Jan 25-26, 2007	Silverado Conference Center, Napa
Roundtable Conference on California's Water Supply-Forging Opportunity in the Face of Crisis	Sept 24-25, 2007	Silverado Conference Center, Napa
Roundtable Conference on State and Regional Energy Issues: Managing the Transition	Oct 9-10, 2007	Silverado Conference Center, Napa
Roundtable Conference on the California Emerging Technology Fund	Mar 15-16, 2007	Vintage/Villagio Inns, Yountville
Roundtable Conference on Transportation and Water Infrastructure: The Role of Public Private Partnerships	Mar 22-23, 2007	Silverado Conference Center, Napa
Workshop on Environmental Initiatives and Energy Adequacy	Aug 30-31, 2007	Meadowood, St. Helena
Public Private Partnerships Workshop	2-Jul-07	The Sterling Hotel, Sacramento
Roundtable Conference on Transportation and Water Infrastructure: The Role of Public Private Partnerships	Mar 22-23, 2007	Silverado Conference Center, Napa
Roundtable Conference on the California Emerging Technology Fund	Mar 15-16, 2007	Vintage/Villagio Inns, Yountville
Conference on Implementation of AB32 -	Jan 25-26,	Silverado Conference

CONFERENCE TITLE	DATE OF EVENT	CONFERENCE LOCATION
The CA Greenhouse Gas Initiative	2007	Center, Napa

CFEE "conducts travel study projects for state and local elected and appointed officials, labor and environmental leaders." CFEE officials claim these "study tours facilitate the exchange of information between public and private sectors in the United States and their counterparts in foreign countries." There have been 25 CFEE-sponsored and utility paid for junkets to foreign countries for CPUC and other state officials since 2000:

Date	Study Topic	Country
2015	Water Resources, Climate Change, Infrastructure	Australia
2015	Water Resources, Information and Communication Technologies, Climate Change, Infrastructure	Singapore
2014	Energy and Infrastructure	Chile
2014	Carbon Capture and Storage Technologies, Alternative Delivery and Finances of Transportation Infrastructure	Canada
2013	Carbon Capture and Storage (CCS), Energy from Waste (EFW), Energy Efficiency Technologies, and Long-term Nuclear Waste Storage	Sweden and Norway
2013	Status of European Climate Programs, Renewable Energy and Stability of Electricity Transmission Grid, Structure of Regional Energy Markets, Transition from Coal to Natural Gas via Hydraulic Fracturing	Poland

Date	Study Topic	Country
2012	California Low-Carbon Fuel Standards and the Role of Brazilian Ethanol and other Biofuels, Advanced "Smart Cities" Technologies, the Reduced Emissions from Deforestation and Forest Degradation (REDD) Program and the Cap & Trade Program	Brazil
2011	Regulatory Structure, Renewable Energy, Smart Meters, Natural Gas Vehicles	Italy
2011	Public Private Partnerships, Water, and Waste-to-Energy Projects	UK and Ireland
2010	Renewable Energy, Infrastructure, Public Private Partnerships, Desalination, Rail	Spain
2010	Renewables & Clean Energy Technology, Public Infrastructure Projects	Canada
2009	Advanced Energy, Low Carbon Vehicle, Public Private Partnerships, Broadband Technologies	China and Hong Kong
2008	Climate Change Issues Regarding Water, Energy and Transportation Infrastructure	New Zealand and Australia
2008	Water, High Speed Rail, Public Private Partnerships	Spain
2007	Energy, Public Private Partnerships	South Africa
2007	Telecommunications & Energy	Japan
2006	Infrastructure & Public Private Partnerships	The Netherlands and Ireland
2006	Renewable Energy Technologies	Brazil, Argentina, and Chile
2005	Renewable Energy Technologies	Belgium, Germany, Denmark, and Ireland

Date	Study Topic	Country
2004	Transportation Infrastructure and Renewable Energy	Italy
2004	Liquefied Natural Gas	South Korea and Australia
2003	Energy Colloquium, Liquefied Natural Gas and Water Policy	France, Spain, Portugal, Germany, Austria, Hungary
2002	Transportation and Sustainable Growth	Berlin, The Hague, Paris
2001	Environmental and Energy Technologies Trade Delegation	China and Inner Mongolia
2000	Natural Resources, Energy and Telecommunications	South Africa

V. EXAMPLES OF CPUC DECISIONS MADE IN SECRET

The CPUC's narrow interpretation of its responsibility to the public in releasing public records, coupled with its practice of meeting outside CPUC open proceeding hearings with investor-owned utilities and the Wall Street banks that work behind the scenes to ensure investors (nor ratepayers) get rewarded, has negatively affected the public and publicly-owned utilities, as discussed below.

A. <u>Example 1: Used and Useful – Nuclear Power Plants</u>

Michael Peevey served as CPUC President for 12 years, from December 2002 to December 2014. Peevey had previously served as President of SCE's parent company, Edison International. In 2004, Peevey supported a fundamental change in the way the CPUC funds major capital expenditures. Under the "used and useful" test, the CPUC determines whether to permit a utility to recover its invested capital after the fact. The utility and its shareholders bear the risk of the investment. Under Peevey, the CPUC did not employ the used and useful test in two major capital expenditure cases (the replacement of steam generators at the Diablo Canyon and San Onofre nuclear power plants). Instead, **for example in the case of San Onofre,** the CPUC allowed SCE to spend up to $680 million for the new steam generators. If the costs exceeded $680,000,000, or if the CPUC later found reason to believe the costs may be unreasonable, the entire cost of the project would be subject to a reasonableness review. (Decision 05-12-040 Page 2)

Under Peevey, the CPUC favored utility investors over utility customers, sparing investors the risk of the steam generator replacement project:

> From an investor point of view, $427 million would be a very large amount to place at risk of cost recovery, especially since it is concentrated in a single project. By way of rough comparison, SCE's total system ratebase in 2003 is about $9 billion, so that if replacement generators were added today, they would comprise about 5% of SCE's total 2003 ratebase. Because this investment is so large, it is essential for SCE to seek, and the Commission to grant, pre-approval of SONGS 2 & 3 SGRP. Pre-approval of SONGS 2 & 3 SGRP means that the Commission finds it reasonable for SCE to replace SONGS 2 & 3 steam generators as described in this Application. While the Commission will retain its full authority, at the completion of SGRP, to review the reasonableness of SCE's construction expenditures and practices, pre-approval means that the Commission may not disallow construction costs, CFC, and Removal and Disposal Costs or their recovery in rates on the ground that SONGS 2 & 3 SGRP was itself unreasonable. Although SCE has recovered its $3.6 billion of past procurement costs, investors and credit rating agencies still remain concerned that regulatory support for SCE's creditworthiness may be withdrawn. SCE must have reasonable assurance that it can recover its investors' money, including a full return of and on the reasonable investment. (Application in SGRP pp. 10-11)

The project failed, causing the plant to close with resulting costs exceeding $4.7 billion. Under Peevey and Picker, the CPUC did not conduct a reasonableness review. Instead, Peevey negotiated -- and Picker ratified -- a secret deal made with SCE in March 2013 in a Warsaw, Poland hotel room. When the matter came under criminal investigation, under Picker, the CPUC authorized over $5,000,000 to block both the investigation and requests for public records. Under Picker, the CPUC refuses to produce records responsive to a Public Records Act request for the 124 related writings it holds.

The CPUC allowed SCE to conduct the proceedings before the CPUC outside public scrutiny. Many of the documents the CPUC used to decide the issues in the failed generator case are kept from the public as "confidential." The meetings and communications amongst Commissioners Peevey, Florio and Picker were held, and conducted, in secret.

When San Onofre's new steam generators failed 11 months after final installation, causing a shut-down of the plant in January 2012, the CPUC reassured Wall Street investors. On 4 October 2012, Morgan Stanley reported meeting with all Commissioner offices at the CPUC. This meeting occurred before the CPUC issued its San Onofre Order Instituting Investigation (OII) in late October 2012.

OCTOBER 04, 2012 GMT

Regulated Utilities

California Visit Takeaways

Morgan Stanley Research
North America

Download the complete report (12 pgs)

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Rajeev Lalwani
+1 212 761 8518
Michael Dandurand
+1 212 761 1817

The key takeaway from our meeting with all Commissioner offices at the CPUC is that regulation will remain balanced. We expect ROEs to remain above-average with supportive rate case resolution this quarter. We are also upgrading EIX to OW, but maintaining ratings on SRE (OW) and PCG (EW).

**.yht

San Bruno resolution getting close, but San Onofre just starting. A settlement relating to the San Bruno explosion is progressing. An agreement may not include all parties, which the CPUC noted some comfort with. We believe our $500mn fine estimate remains appropriate. Conversely, a San Onofre nuclear plant investigation is likely, but the CPUC appears to be reserving judgment on the cause/recovery. As a result, we do not expect a near-term EPS hit to EIX/SRE.

The CPUC would eventually ratify a deal made between Southern California Edison executives and CPUC officials in at the Bristol Hotel in Warsaw, Poland, making utility customers pay the majority of costs of the closed plant -- not the shareholders.

B. <u>Example 2: San Bruno Gas Explosion</u>

On 9 September 2010 at approximately 6:11 p.m., a portion of gas Line 132 (Segment 180) ruptured in a residential neighborhood of the City of San Bruno. Gas escaping from the rupture ignited, causing a fire that killed eight people and injured 58 others. The fire also damaged 108 homes, 38 of which were completely destroyed.

In December 2013, PG&E filed its 2015 Gas Transmission and Storage (GTS) Rate Case, asking the CPUC to impose $1,209, 000,000 in rates to maintain and modernize PG&E's pipelines. PG&E's request to the CPUC to take more money from ratepayers was a sensitive issue. In May 2013, seven months before PG&E's rate increase filing, CPUC staff proposed to order PG&E to pay $2,250,000,000 in fines for failing to maintain its gas main in San Bruno, California. It was PG&E's line failure that resulted in the September 2010 catastrophic explosion that leveled the Bay Area neighborhood and killed eight people:

The morning after the 2010 explosion in San Bruno, a PG&E utility inspector looks at the gas main that ruptured.
(Don Bartletti / Los Angeles Times)

PG&E officials wanted Commissioners Florio, Peevey and their staff to make sure PG&E's preferred Administrative Law Judge (ALJ) was appointed to hear PG&E's GTS rate increase case. On 14 January 2014, PG&E Vice President of Rates and Regulation, Brian K. Cherry, wrote to Peevey's Chief of Staff: "As long as ALJ Wong has the case (which Florio confirms), we are ok with what Mike (Peevey) wants to do on the assignment." Cherry asked Peevey's Chief of Staff, Carol Brown, "Can you get it done ASAP please?" Cherry, Brown, Peevey and Florio are pictured here:

At 8:42 a.m. on 17 January 2014, PG&E Regulatory Manager, Eileen Cotroneo, emailed Brian K. Cherry: "The GTS Case assignment appeared on the daily calendar -Assigned to ALJ Long and Commissioner Peterman. I will issue a note to our team." PG&E's Vice President found this to be disturbing news. Thirty-seven (37) minutes after Ms. Controneo notified Cherry of Long's appointment, Cherry emailed Peevey's Chief of Staff, Carol Brown: "Is this right? Judge Long? What happened to Wong?"

At 9:49 a.m. that day -- about an hour later -- PG&E Cherry wrote Peevey's Chief of Staff, Brown: "Please, please check. This is a major problem for us. Florio said he would agree to help Peterman if Wong got it."

PG&E's Cherry then turned to Commissioner Peevey at 9:55 a.m. that same day, 17 January 2014: "This is a problem. Hope Carol can fix it." Two hours later, Cherry again wrote her: "There is a huge world of difference between Long and Wong. I'm not sure we could get someone worse. This is a very important case that is now in jeopardy." A few hours later, Commissioner Florio joined the back-room wheeling and dealing and told Cherry at 1:18 p.m.:

> "I'm horrified! He still has not produced a PD for Sempra's Psep/TCAP after much prodding and cajoling—we are considering asking that another ALJ be assigned to finish for him. Plus he may retire any day, and uses that as a threat to deflect any direction. Sepideh spoke to John Wong and he said he's just too overloaded, which we didn't know. John is a true workhorse so it must be true. If I were you I would bump him—you really can't do any worse! Even a brand new ALJ would at least work hard and try—you'll get neither from him … Keep me posted and I'll do what I can on this end…

Florio referred to his Chief of Staff, Sepideh Khosrowjah, contacting John Wong. She is pictured here:

Sepideh Khosrowjah
Chief of Staff for Florio

Ten days later on 27 January 2014, at 3:36 p.m., Peevey's Chief of Staff, Carol Brown, sent a cryptic note with two names: "Wong and Peterman" -- the ALJ and Commissioner PG&E wanted assigned to its GTS case. In fact, *those two were assigned* those roles. Two minutes later at 3:38 p.m., PG&E's Brian Cherry wrote Carol Brown with profuse thanks: "Thank You, Thank You. Thank You."

This judge-shopping scheme to give PG&E its preferred judge was an example of CPUC policy to please utility investors, even when it meant breaking the rules. Another email from an owner of five million PG&E shares of stock captured the point:

> And the CA Commission, staff, Governor and legislature **have to convince institutional investors it's still a good place to put money** into. Right now one would have to say CA went from being one of the better regulatory environments, to average. AT BEST! Evidence has been provided by EIX and SRE being relative underperformers as well. If all relevant parties in CA believe that there is what I would characterize as a "captive" audience of utility investors, I would emphatically say that is a mistaken view. Go back to the mid-1990's, you couldn't get anyone to buy utilities.

Even when PG&E rule violations caused the San Bruno gas explosion, one Commissioner argued strict accountability would raise the price of capital. In October 2013, Commissioner Ferron made a revealing statement about San Bruno and San Onofre. Ferron admitted in early October he met with groups of utility investors "every few quarters or so." According to Ferron, the investor groups represented "over $3 trillion dollars in assets under management." Ferron described the groups as knowledgeable about utilities, "These specific individuals are the ones within their respective organizations that eat, sleep and breathe public utilities across the country and around the world." (referring to the Wall Street $3 Trillion Group)

Ferron reported the Wall Street $3 Trillion Group was "very focused on learning more about the two big "headline issues" in California: San Bruno and San Onofre." Despite their focus on learning more about San Bruno and San Onofre issues, Ferron invited incredulity when he claimed he "could not and, of course, would not talk about these cases in any way shape of form" with the Wall Street $3 Trillion Group.

Ferron then claimed "these investors did not attempt to engage in a discussion of pending adjudicatory cases and were very respectful of our ex parte rules." The written record shows the groups did not report a single conversation about the content of discussions with Ferron and commissioners under CPUC ex parte rules.

Ferron reported the Wall Street $3 Trillion Group was concerned about "politics surrounding" the San Bruno and San Onofre cases which had "played out in a dramatic and public manner in the press." Their "collective judgment" was President Peevey had "rehabilitated" California's image as a "banana republic." Through "the actions of this Commission over a wide range of cases watched closely by the investment community, California has moved from being a high-risk outlier to being somewhere in the middle of the pack in terms of risk perception." With no empirical support, Ferron argued:

> [T]his reduction in risk has led to a direct reduction in the cost of financing capital for the utility sector in California. If you do the math, the reduction in the risk premium -- the reduction in the incremental cost of capital to our utilities -- when applied to the balance sheet of our utilities, is equal to several hundred million dollars every year in direct savings to rate-paying customers. In short, the ratepayer is ultimately the direct benefactor of this Commission making decisions that improve the investment climate in California.

Ferron argued SCE and PG&E should not be required to fully pay for the consequences of the San Onofre and San Bruno disasters to keep investors from seeing California as "unfriendly place." If not, investors could demand "an incremental risk premium for an extended period of time" which would "cost ratepayers multiple billions of dollars in added expense."

Ferron, a London banker at Deutsche Bank for 20 years, was put on the CPUC to deliver this message. In January 2011, the early days of the Brown administration, Wall Street worried Brown would restore consumer control of the CPUC. In late January 2011, Brown appointed to the CPUC two new commissioners the utilities perceived as consumer-friendly. Brown's third appointment could have tipped the balance on the 5 member board in favor of consumers, leaving Peevey without a majority.

On 11 January 2011, a senior investment analyst at PG&E reported that a frequent visitor of Peevey, Brian Chin of Citigroup, downgraded two out of the three utilities in California, Edison International and PG&E, on the uncertainty and potential shifting dynamics in the regulatory arena. Chin cited the appointment of three new Commissioners could result in a significant change to the current constructive regulatory environment.

Chin, according to the PG&E analyst, was concerned about: 1) the CPUC has been criticized in the media for being too close to the Utilities, and may "pull back" to quiet some of the critics, and 2) President Peevey may reconsider his role at the CPUC as a result of the Commissioners who are appointed by Governor Brown.

A major risk cited by Chin about the potential new appointees to the Commission was that there may not be a balance between the need for regulatory oversight while still allowing the Utilities to earn a reasonable rate of return. Media reports had referenced potential candidates whose backgrounds are in politics and environment/wildlife advocacy, which historically do not align with constructive regulatory policies, so reported PG&E's analyst.

On the day it was sent, PG&E executive Brian Cherry forwarded that 11 January 2011 analyst report to Peevey. The response from Peevey to Cherry: "You should find a way to get this info to Brown as he makes his decisions on Commissioners ASAP. Probably best coming from a non-utility source, such as investment banker(s)." In response, Cherry wrote Peevey: "Done." Peevey told Cherry later on the same day: "You may have reason for concern. Major changes coming and I fear lack of knowledge of subject matter. You will miss Arnold."

On 26 January 2011 the PG&E investment analyst reported continued speculation by the stock analysts following California utilities:

> Key questions raised by analysts in published reports, as exemplified by the Deutsche Bank and UBS reports attached, as well as questions we've received in IR include:
>
> • Will Mike Peevey continue as President of the commission?
> • Who will be the third commissioner appointed to the CPUC?
> • With three new commissioners, what will be the overall direction of the 5-member Commission; and whether it will be much more consumer oriented to the detriment of investors?

On 27 January 2011, PG&E's senior investment analyst reported JP Morgan had downgraded PGE from a "buy" to "hold." PG&E's Cherry forwarded the report to Peevey, who wrote back: "As I suggested before, this info should go to the Governor's office, probably best to Nancy McF. Jerry has to be made aware that actions have consequences and the economy is best off with a stable utility sector." At 12:46 p.m., Cherry wrote Peevey: "Nancy asks if you have any names you would recommend. You can call her directly if you'd like."

In March 2011, Jerry Brown made his decision not to appoint a consumer advocate, but instead, chose a long-time investment banker, Mark Ferron. Ferron in October 2013 delivered Wall Street's message for the CPUC to go easy on SCE and PG&E for the San Onofre and San Bruno disasters. Ms. McFadden, a former PG&E legislative advocate, did not recuse herself from the decision on who to appoint to the CPUC, despite her ownership of PG&E stock options.

In his statement, Ferron admitted he met with three groups of investors but claimed he did not discuss the San Onofre and San Bruno cases in "any way, shape or form." However, on 18 June 2013 (four months before Ferron's October 2013 remarks to the CPUC), Greg Gordon, though his assistant, told Ferron the topics of discussion would include: "[T]he legal framework regarding the CPUC's ability and flexibility to implement fines and penalties."

The Gordon email is quite remarkable because it gives great insight into the true nature of the sub-rosa discussion between CPUC Commissioners and Wall Street:

/ / /

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/ / /

From: Susan Davies [SDavies@isigrp.com]
Sent: 6/18/2013 5:42:11 PM
To: 'Banks, Juliane' [juliane.banks@cpuc.ca.gov]
Subject: RE: Meeting with Commissioner Ferron Wed 6/19 at 11am in San Francisco

Hi Juliane,

Thanks for asking and I can also give you some history as well.

Greg Gordon has hosted meetings before with other California Commissioners including President Peevey and Carol Brown, both in person and via video phone from our offices here in NY.
He has been covering the CPUC's policy decisions for 20 years, first as a regulatory analyst at Regulatory Research Associates and since at several other institutions. ISI Group is a research only organization, although the members of the group that is attending include both equity and credit investors in CA's utility infrastructure.

Greg realizes there are several pending cases in front of the CPUC, including PG&E's electric rate case, the Pipeline case, the SCE case regarding the San Onofre plant, etc. and that your office cannot/will not "predict the future" on cases that have not yet been decided.
The issues/topics we will want to cover will focus on is Commissioner Ferron's philosophical position, given his record as a Commissioner at the CPUC, as it pertains to different matters that may be before the Commission now or in the future, NOT specific questions as to how he might rule "up or down" on any pending or future issues before the Commission. Some attendees might want to pose hypothetical questions to your team on how they think the Commissioner would respond to different economic or regulatory scenarios, given his regulatory philosophy and decision making framework.

These issues might include:

Historic decisions and protocol with regard to the prudence and usefulness of assets and the precedence of those decisions.

The current ROE/Cap structure framework and its durability.

The need/desire for continued infrastructure investment in power and gas and how that gets paid for under different economic forecasts.

Rate design issues and how they are resolved as it pertains to solar tariffs and other rates.

The legal framework regarding the CPUC's ability and flexibility to implement fines and penalties.

The group looks forward to seeing you on Wednesday.

C. <u>Example 3: IID Renewable Energy</u>

The Imperial Irrigation District (IID) is a public entity organized in 1911 under the California Irrigation District Law.[2] The IID, referred to as a "balancing authority," has the power under law to provide electric service within its 6,483 square mile boundaries. As a balancing authority, IID has the responsibility for integrating resource plans ahead of time, maintaining load interchange and generation balance within the IID territory, and supporting Interconnection frequency in real time.[3] IID serves electricity to more than 150,000 customers in Imperial County and parts of Riverside and San Diego counties.[4] The IID balancing area adjoins the California Independent Systems Operator (ISO) balancing area[5]:

[2] Codified at Division 11 of the California Water Code.

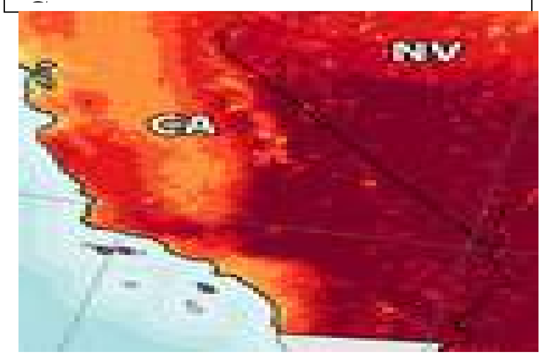
[3] http://www.nerc.com/files/glossary_of_terms.pdf

[4] http://www.iid.com/about-iid/an-overview/iid-history

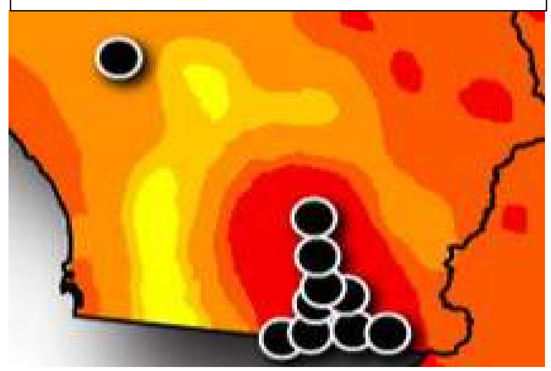
[5] http://www.energy.ca.gov/maps/serviceareas/balancing_authority_areas.pdf

Over **8,480** megawatts (MW) of renewable energy has been identified as available for development in Imperial County, according to California's lead energy agencies. Further, the United States government's primary laboratory for renewable energy, energy efficiency research, and development -- the National Renewable Energy Laboratory (NREL) -- has identified Imperial County as some of the most favorable regions for solar and geothermal energy in the nation, as shown here on two NREL energy potential maps:

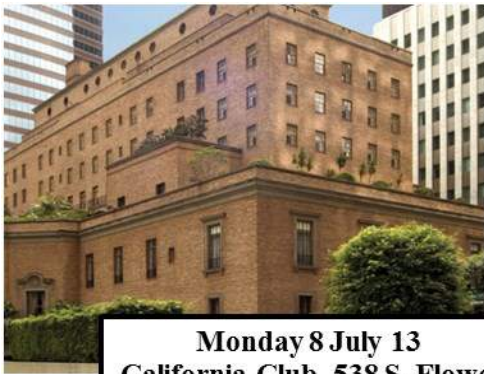
NREL Map Solar Resources Concentrated in Imperial



NREL Gives Imperial County Most Favorable Geothermal



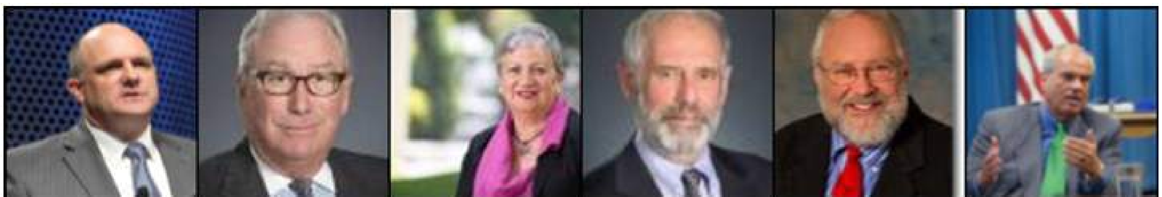
The CPUC issued rulings and decisions committing access to the California power grid for IID to develop its renewable energy in the Imperial Valley. However, after San Onofre went down, the CPUC, under Picker, blocked IID's effort to fully develop Imperial County renewables. Picker was involved in the issue while still a senior adviser to the Governor of California. On 8 July 2013, Peevey arranged a secret meeting at the members-only California Club to discuss what energy sources would be called upon to replace that lost at San Onofre. The invitation to Picker read: "President Peevey has reserved a private room on the 3rd floor of the California Club** Time: 6:00-9:00pm (6:00 Drinks 6:30 pm Dinner):"



Monday 8 July 13
California Club 538 S. Flower

California Club, Third Floor
Private Dinning Room

The participants in the 8 July 2013 meeting included the following government officials:



CALISO President Stephen Berberich	**CPUC President Michael Peevey**	**Chair California Air Resources Board Mary Nichols**	**Gov Brown Energy Adviser Michael Picker**	**Chair Cal Energy Commission Robert Weisenmiller**	**Gov Brown Adviser Jobs, Business Michael E. Rossi**

Picker was on an email chain relating to his opposition to IID gaining access to the California grid for the Imperial County renewables. The email chain started on 8 August 2014 (4:09 PM) with ISO Director of State Government Affairs, Mary McDonald, writing to Governor Brown's Deputy Legislative Secretary, Martha Guzman-Aceves. The email related to IID's efforts to increase transportation of its geothermal, solar and other renewable energy sources through the ISO to energy supply markets:

> At this week's Assembly Appropriations Committee hearing on SB 1139 (Hueso), Kevin Kelley the General Manager of Imperial Irrigation District stated that a recent ISO technical addendum finds that 462 MW of export capacity available from llD into the ISO

(http://www.caiso.com/DocumentsfiechnicalAddendumlmperialCountvDeliverabilitv. pdf). However, that 462 MW that he referenced is being used to import existing generation from llD into the ISO (Maximum Import Capability, MIC). As explained in the addendum, transmission additions approved in the ISO's 2013-14 transmission planning cycle will enable future additional amount of deliverability for the overall Imperial zone of up to 1,000 MW. Based on a review of the CPUC's approved power purchase agreements we have determined that all of the 1,000 MW is expected to be used by generation that is already moving forward as a result of having CPUC approval and are connecting directly to the ISO.

On 8 August 2014 at 4:22 p.m. -- thirteen minutes after Ms. McDonald sent her email -- ISO's Vice President for Policy and Client Services, Karen Edson, forwarded Ms. McDonald's email to CPUC Commissioner Michael Picker (previously on the Governor's renewable energy staff) accusing IID General Manager, Kevin Kelley, of making "incorrect representations to the Legislature." Commissioner Picker sent a reassuring email to ISO policy chief Edson mocking, but not copying, GM Kelley:

> He (GM Kelley) still believes that you guys (the ISO) told him that there was adequate transmission capacity to move 500 MW of geothermal to the coast; and that (not clear that he actually asked the question) geothermal from lmperial is just what is needed to replace San Onofre. I said that Kevin Kelley was wrong about how to reach the lmperial County deliverability and that the physics of the system made it unlikely that additional remove resources help with reliability on the coast without another set of transmission improvements that provide delivery (or VARS) at someplace near San Onofre. He said that the didn't understand what a VAR was, and then went on to complain about the CPUC leg staff's testimony about economic impacts.

Again, the work of this special group was carried out in secret; their decisions resulted in SCE (Edison) replacing most of San Onofre's lost power with electricity based on natural gas. One example of the closed-door meetings at which the energy regulators conducted business occurred on 17 June 2014 at the home of Air Resources Board Chair, Mary Nichols. An email from California

Energy Commission (CEC) Chairman Robert Weisenmiller notified participants the meeting was scheduled for Tuesday, June 17, 2014, 3:15 PM-5:00PM at Mary Nichols' residence. Those scheduled to attend the meeting were Air Resources Board Chair Mary Nichols, CEC Executive Director Rob Oglesby, CEC Commissioner Janea Scott, CEC Chair Bob Weisenmiller, ISO President Steve Berberich, CPUC Commissioners Peevey and Picker, and Senior Adviser to Governor Brown, Cliff Rechtschaffen.

VI. CPUC VIOLATES PUBLIC RIGHT OF ACCESS

A. Public Denied Access

The California Public Records Act (PRA) expressly governs and provides for the public to have access to the writings of the CPUC. See, Govt. Code §§ 6252, 6253(g) and 6253.4 The public has a right to inspect public records of state agencies, which includes every state Commission. See, Govt. Code §§ 6253(g), and 6252. The legislature directed the CPUC to establish written guidelines for the public to obtain access to CPUC records. Govt. Code § 6253.4(a).

B. Vast Collection of Secret Records at the CPUC

The writings at the CPUC consist of those it creates and those it receives. The records the CPUC generates track the collective concurrence decision making process. The records it receives influence the decision making process at the CPUC. Instead of releasing records under the PRA, the CPUC Commissioners and staff work in tandem with the utilities to deny public access to the CPUC's decision making process.

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VII. RECOMMENDED PRA REFORMS

Based on this record, the following course of action is recommended in the instant OIR proceeding, both retroactively and prospectively. First, the CPUC should issue a report identifying all records granted confidential treatment. Second, any record used by the CPUC to make financial decisions that placed a financial burden on utility customers should be ordered released to the public. Third, the CPUC should release all of its private communications with Wall Street interests.

Fourth, on a going forward basis, the CPUC should discontinue the practice of receiving and participating in private emails and private visitations from Wall Street investor interests. Fifth, the CPUC should agree that its assertion of public record exemptions are subject to Superior Court review under the Public Records Act. As for records relating to matters not involving requests for utility customers to pay money, the CPUC should adopt the procedures the Securities & Exchange Commission uses under the Freedom of Information Act.

The IID respectfully submits that the only records of the CPUC which may not be subject to immediate disclosure would be those requests of "market participants" for data or documents that fit the narrow definition of having a material impact on a procuring party's market price for electricity, recognizing that the burden rests upon the filing party to prove the submittal to be eligible for confidential treatment.

Specifically, IID submits that the below listed data/records should be subject to public disclosure:

*Third party documentation subject to an NDA unless otherwise exempt;

*Documents subject to attorney-client privilege unless otherwise exempt;

*Pricing data to the same extent required to be disclosed in the public sector;

*Evaluation criteria utilized for project ranking;

*Energy procurement data not specifically exempt under state or federal law;

*RPS solicitation process data;

*Reports/data relevant to the transmission planning process;

In light of the above, IID respectfully objects to any carte blanche disclosure exemption that extends beyond the parameters as set forth above. In addition, in regards to any data or records that might be so restricted, such should be subject to disclosure upon approval action by the Commission or within a very brief period thereafter.

The IID believes a procedure that adds steps beyond that required by the Public Records Act – such as the Working Group's proposal for a first look by the utilities, is not needed and represents another way in which the Wall Street-run investor-owned utilities unduly influence and control the actions of the Public Utilities Commission. Rather, the CPUC should follow the California Constitution and Public Records Act that requires statutes and procedures that limit public access to be narrowly construed, and broadly construe those that provide access.

A presumptive matrix identifying documents predetermined to be confidential or public would impermissibly replace the process set forth under the PRA and the authority of the California Constitution. IID's position as to matrix documents is attached as Appendix 1, hereto.

VIII. CONCLUSION

James Madison taught us that knowledge will forever govern ignorance, and a people who mean to be their own governors must arm themselves with the power knowledge gives.   A popular government without popular information or the means of acquiring it is but a prologue to a farce, or a tragedy, or perhaps both.

The CPUC cannot lawfully stop a review of whether it is legitimately withholding documents from the public by misconstruing a provision of law that assigned review of the CPUC's regulatory decisions to the appellate court.. As our Constitution states, "The people have the right of access to information concerning the conduct of the people's business, and, therefore, ** the writings of public officials and agencies shall be open to public scrutiny." Cal State Const. Art 1, Sect 3.

AGUIRRE & SEVERSON LLP

Dated: March 16, 2016

By: *\/s/Maria C. Severson*
Michael J. Aguirre
Maria C. Severson

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Improve Public Access to Public Records Pursuant to the California Public Records Act.	R. 14-11-001 (Filed November 6, 2014)

DECLARATION OF MARIA C. SEVERSON IN SUPPORT OF IMPERIAL IRRIGATION DISTRICT'S REPORT ON THE CPUC'S HISTORY RELATING TO ACCESS TO PUBLIC RECORDS AND COMMENTS FOLLOWING WORKSHOP

(INDEX OF DOCUMENTS REFERENCED)

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San Diego, CA 92101
Telephone: (619) 876-5364
Facsimile: (619) 876-5368
Attorneys for Imperial Irrigation District

1. I am an attorney duly licensed to practice before all of the courts of the State of California, and I along with my partner, Michael Aguirre, with the law firm of Aguirre & Severson LLP, am one of the attorneys of record for Imperial Irrigation District in this action. Except where otherwise stated, I have personal knowledge of the matters stated herein and if sworn as a witness could and would testify competently thereto.

2. Attached as Exhibits 1 through 4 are true and correct copies of the following documents referenced in the Comments filed contemporaneously herewith.

1. **EMAILS**
2. **EXCERPTS FROM PUBLIC UTILITY CODE SECTION 748 REPORTS**
3. **EXCERPTS FROM STATISTICAL REPORT AND 10-KS RE: NUMBER OF STOCKHOLDERS AT EDISON, SEMPRA, PG&E & SDG&E**
4. **EXCERPTS FROM EDISON, SEMPRA, PG&E & SDG&E 10-KS RE: MARKET VALUE AND NUMBER OF SHARES**

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I declare under penalty of perjury and under the laws of the State of California that the foregoing is true and correct. I have executed this declaration in San Diego, California on March 16, 2016.

Respectfully Submitted,

Dated: March 16, 2016

By: */s/ Maria C. Severson*

Maria C. Severson, Esq.
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501 West Broadway, Suite 1050
San Diego, CA 92101
Telephone: (619) 876-5364
Attorneys for
IMPERIAL IRRIGATION DISTRICT

EXHIBIT 1

From: Cherry, Brian K
Sent: 1/27/2011 12:46:34 PM
To: 'mp1@cpuc.ca.gov' (mp1@cpuc.ca.gov)
Cc:
Bcc:
Subject:

Nancy asks if you have any names you would recommend. You can call her directly if you'd like.

From: Peevey, Michael R.
Sent: 1/11/2011 3:17:01 PM
To: Cherry, Brian K (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=BKC7)
Cc:
Bcc:
Subject: Re: Analyst Report - Citigroup Downgrade

You may have reason for concern. Major changes coming and I fear lack of knowledge of subject matter. You will miss Arnold.

From: Cherry, Brian K
To: Peevey, Michael R.
Sent: Tue Jan 11 15:10:55 2011
Subject: Re: Analyst Report - Citigroup Downgrade

Done. We worry about our GRC changes too.

From: Peevey, Michael R. [mailto:michael.peevey@cpuc.ca.gov]
Sent: Tuesday, January 11, 2011 12:23 PM
To: Cherry, Brian K
Subject: RE: Analyst Report - Citigroup Downgrade

You should find a way to get this info to Brown as he makes his decisions on Commissioners ASAP. Probably best coming from a non-utility source, such as investment banker(s).

From: Cherry, Brian K [mailto:BKC7@pge.com]
Sent: Tue 1/11/2011 9:16 AM
To: Brown, Carol A.; Peevey, Michael R.; Clanon, Paul
Subject: FW: Analyst Report - Citigroup Downgrade

FYI

From: Lam, Lisa
Sent: Tuesday, January 11, 2011 8:40 AM
To: Officers of PG&E Corporation; Officers of Pacific Gas and Electric
Cc: Investor Relations (list)
Subject: Analyst Report - Citigroup Downgrade

Yesterday, Brian Chin of Citigroup downgraded two out of the three utilities in California, Edison International and PG&E, on the uncertainty and potential shifting dynamics in the regulatory arena. Chin cited that the possible non-confirmation of Commissioner Ryan and the appointment of three new Commissioners could result in a significant change to the current constructive regulatory environment.

Chin noted that his view on California's regulatory space is more focused on how the CPUC could evolve in the longer term, in six months to a year. His concern is 1) the CPUC has been criticized in the media for being too close to the Utilities, and may "pull back" to quiet some of the critics, and 2) President Peevey may reconsider his role at the CPUC as a result of the Commissioners who are appointed by Governor Brown.

A major risk cited by Chin about the potential new appointees to the Commission is that there may not be a balance between the need for regulatory oversight while still allowing the Utilities to earn a reasonable rate of return. Media reports have referenced potential candidates whose backgrounds are in politics and environment/wildlife advocacy, which historically do not align with constructive regulatory policies.

For the first six trading days of the year, PCG is down 2.8% at $46.52, compared to the average comparator group company, which is up 0.1%. The S&P 500 year-to-date is up 1.0%, and the Dow Jones Utility Average 0.1%. Over the past week, we have received a downgrade from Barclays and NTSB recommendations that generated a number of articles in the media, raising investor concerns about the implications for PG&E. And while Morgan Stanley upgraded PCG on Thursday, January 6, the overall tone from investors in 2011 remains cautious.

For your reference, the full report is attached.

Lisa

The contents of this email are provided solely for your information and are not intended as investment advice. We do not intend to endorse the opinions expressed in any externally prepared reports that may accompany this email and you should not rely on them for investment advice.

Lisa Lam

PG&E Investor Relations

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San Francisco, CA 94105

(415) 817-8137

From: Peevey, Michael R.
Sent: 1/11/2011 3:17:01 PM
To: Cherry, Brian K (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=BKC7)
Cc:
Bcc:
Subject: Re: Analyst Report - Citigroup Downgrade

You may have reason for concern. Major changes coming and I fear lack of knowledge of subject matter. You will miss Arnold.

From: Cherry, Brian K
To: Peevey, Michael R.
Sent: Tue Jan 11 15:10:55 2011
Subject: Re: Analyst Report - Citigroup Downgrade

Done. We worry about our GRC changes too.

From: Peevey, Michael R. [mailto:michael.peevey@cpuc.ca.gov]
Sent: Tuesday, January 11, 2011 12:23 PM
To: Cherry, Brian K
Subject: RE: Analyst Report - Citigroup Downgrade

You should find a way to get this info to Brown as he makes his decisions on Commissioners ASAP. Probably best coming from a non-utility source, such as investment banker(s).

From: Cherry, Brian K [mailto:BKC7@pge.com]
Sent: Tue 1/11/2011 9:16 AM
To: Brown, Carol A.; Peevey, Michael R.; Clanon, Paul
Subject: FW: Analyst Report - Citigroup Downgrade

FYI

From: Lam, Lisa
Sent: Tuesday, January 11, 2011 8:40 AM
To: Officers of PG&E Corporation; Officers of Pacific Gas and Electric
Cc: Investor Relations (list)
Subject: Analyst Report - Citigroup Downgrade

Yesterday, Brian Chin of Citigroup downgraded two out of the three utilities in California, Edison International and PG&E, on the uncertainty and potential shifting dynamics in the regulatory arena. Chin cited that the possible non-confirmation of Commissioner Ryan and the appointment of three new Commissioners could result in a significant change to the current constructive regulatory environment.

Chin noted that his view on California's regulatory space is more focused on how the CPUC could evolve in the longer term, in six months to a year. His concern is 1) the CPUC has been criticized in the media for being too close to the Utilities, and may "pull back" to quiet some of the critics, and 2) President Peevey may reconsider his role at the CPUC as a result of the Commissioners who are appointed by Governor Brown.

A major risk cited by Chin about the potential new appointees to the Commission is that there may not be a balance between the need for regulatory oversight while still allowing the Utilities to earn a reasonable rate of return. Media reports have referenced potential candidates whose backgrounds are in politics and environment/wildlife advocacy, which historically do not align with constructive regulatory policies.

For the first six trading days of the year, PCG is down 2.8% at $46.52, compared to the average comparator group company, which is up 0.1%. The S&P 500 year-to-date is up 1.0%, and the Dow Jones Utility Average 0.1%. Over the past week, we have received a downgrade from Barclays and NTSB recommendations that generated a number of articles in the media,
raising investor concerns about the implications for PG&E. And while Morgan Stanley upgraded PCG on Thursday, January 6, the overall tone from investors in 2011 remains cautious.

For your reference, the full report is attached.

Lisa

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Lisa Lam

PG&E Investor Relations

One Market Plaza, Spear Tower, 2400

San Francisco, CA 94105

(415) 817-8137

From: Peevey, Michael R.

Sent: 1/27/2011 12:12:17 PM

To: Cherry, Brian K (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=BKC7); Brown, Carol A. (carol.brown@cpuc.ca.gov)

Cc:

Bcc:

Subject: RE: Analyst Report - J.P. Morgan Downgrade

As I suggested before, this info should go to the Governor's office, probably best to Nancy McF. Jerry has to be made aware that actions have consequences and the economy is best off with a stable utility sector.

From: Cherry, Brian K [mailto:BKC7@pge.com]
Sent: Thursday, January 27, 2011 12:08 PM
To: Peevey, Michael R.; Brown, Carol A.
Subject: Fw: Analyst Report - J.P. Morgan Downgrade

More news from the analysts.

From: Lam, Lisa
Sent: Thursday, January 27, 2011 10:31 AM
To: Officers of PG&E Corporation; Officers of Pacific Gas and Electric
Cc: Investor Relations (list)
Subject: Analyst Report - J.P. Morgan Downgrade

This morning, Andy Smith of J.P. Morgan downgraded Edison International and PCG, from "BUY" to "HOLD", based on the regulatory uncertainty in California that is suggested with the two new commissioners appointed to the CPUC earlier in the week.

Similar to the reports circulated yesterday from Deutsche Bank and UBS, J.P. Morgan stated that investors fear the Governor could have swung the Commission too far in the consumer-oriented direction with the appointments of Mike Florio and Catherine Sandoval, which ultimately could be detrimental to the utilities' ability to recover significant capital investments in the future.

The report also expressed concerns around Mike Peevey remaining in his current role as President of the Commission. The investment community has not received a clear indication from the governor that commissioner Peevey will continue to serve as President and investors would view Peevey's departure from the CPUC negatively given his even-handed leadership of the Commission.

In trading today, the utility sector is performing in line with the broader markets. PCG is up approximately 0.6% compared to the S&P 500 which is up 0.2% and the Dow Jones Utility Average which is up 0.3%. PCG has already significantly underperformed year-to-date and today's report may reflect information already incorporated in the stock price.

For your reference, the full report is attached.

Lisa

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San Francisco, CA 94105

(415) 817-8137

From: Peevey, Michael R.
Sent: 1/27/2011 2:09:47 PM
To: Cherry, Brian K (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=BKC7)
Cc:
Bcc:
Subject: RE:

Brown is not coming. Too much stuff in the Chron---Matier and Ross, editorial. Ugh. Nancy McE says she will be there. But she knows Red I assume. If not, I will set him up.

As far as Hawaii goes, great. Carol and I leave February 3 for a week (its my B-day).

-----Original Message-----
From: Cherry, Brian K [mailto:BKC7@pge.com]
Sent: Thursday, January 27, 2011 2:04 PM
To: Peevey, Michael R.
Subject:

I am bumping someone from our table and bringing Redacted tonight. I've asked for his Bio to pass on to the transition team. If you could introduce him as necessary that would be great.

BTW - I'm in Hawaii and won't see you tonight. Sorry, I booked the tickets with miles a year ago.

From: Cherry, Brian K

Sent: 1/27/2011 2:24:29 PM

To: 'michael.peevey@cpuc.ca.gov' (michael.peevey@cpuc.ca.gov)

Cc:

Bcc:

Subject: RE:

Not surprising. Nancy hasn't met Re but I will make sure she is prepped. Introduce her to him as will Tom.

Will is preparing a bio. He would be a great pick. Says he would serve a full term but that might be a plus too. You need to chat with him. He doesn't understand how political these things are.

Congrats on the BDay. Everyone that arrives for me is cause for celebration given the alternative !

----- Original Message -----
From: Peevey, Michael R. [mailto:michael.peevey@cpuc.ca.gov]
Sent: Thursday, January 27, 2011 02:09 PM
To: Cherry, Brian K
Subject: RE:

Brown is not coming. Too much stuff in the Chron--Matier and Ross editorial. Ugh. Nancy McF says she will be there. But she knows Re I assume. If not, I will set him up.

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Commissioner Ferron's Report on Meetings with Utility Investors, October 3, 2013

This week I met with 3 groups of investors, something which we all do every few quarters or so. Collectively these investors represented more than $3 trillion dollars in assets under management. (That's Trillion with a "T"). These specific individuals are the ones within their respective organizations that eat, sleep and breathe public utilities across the country and around the world.

You'll not be surprised that they were very focused on learning more about the two big "headline issues" in California: San Bruno and San Onofre. Of course, I could not and, of course, would not talk about these cases in any way shape of form. I must stress that these investors did not attempt to engage in a discussion of pending adjudicatory cases and were very respectful of our ex parte rules.

But we have to keep in mind that these investors are watching from the outside with some confusion and great concern as the politics surrounding these cases have played out in a dramatic and public manner in the press.

So I asked them for a kind of report card on how the Commission has been doing, and how the investment climate in California is perceived. To the extent that there was a collective judgement, here is what I heard:

In the aftermath of the Energy Crisis of 2001 and the bankruptcy of PGE and near bankruptcy of EIX, California was perceived as a very high risk regime for investors – California was seen as an capital unfriendly, "banana republic" (their words) - - and that period represented a kind of "lost decade" for investors in California utilities. But thanks to the cumulative actions of the CPUC over the next decade, led by President Peevey, investors absorbed their losses and the image of California as a banana republic was for the most part rehabilitated.

Three years ago, with a new Governor and three (now four) new commissioners, there was again considerable nervousness about the future direction of the regulatory and investment climate in California. But through the actions of this Commission over a wide range of cases watched closely by the investment community, California has moved from being a high-risk outlier to being somewhere in the middle of the pack in terms of risk perception. This is despite California and this Commission taking a serious approach to climate change and a concerted approach to renewables, something that is somewhat unique and of some concern to many sceptical investors.

This reduction in risk has led to a direct reduction in the cost of financing capital for the utility sector in California. If you do the math, the reduction in the risk premium - - the reduction in the incremental cost of capital to our utilities - - when applied to the balance sheet of our utilities, is equal to several hundred million dollars every year in direct savings to rate-paying customers. In short, the ratepayer is ultimately the direct benefactor of this Commission making decisions that improve the investment climate in California.

Of course the motto on Wall Street is: "So what have you done for me lately?" They are ruthlessly focused on the future. So these folks will look through all the rhetoric, and will look directly at the actions we take - specifically in the two big headline issues.

So, my conclusion: I'm not talking about policy, I'm not talking about what we should or shouldn't do for any of these headlines cases. I'm just talking arithmetic. If, for whatever reason, we were to return to where the investor perception of California is that it is an capital-unfriendly place and that IF investors demand an incremental risk premium for an extended period of time - as it did a decade ago - this would cost ratepayers multiple billions of dollars in added expense. That's Billions with a "B".

Personally, I find this arithmetic very sobering.

From: Cherry, Brian K
Sent: 2/23/2011 3:58:04 PM
To: Michael R. Peevey (michael.peevey@cpuc.ca.gov) (michael.peevey@cpuc.ca.gov); Brown Carol (cab@cpuc.ca.gov) (cab@cpuc.ca.gov)
Cc:
Bcc:
Subject: FW: Analyst Reports - GRC PD & Alternate PD

FYI

From: Lam, Lisa
Sent: Wednesday, February 23, 2011 3:51 PM
To: Officers of PG&E Corporation; Officers of Pacific Gas and Electric
Cc: Investor Relations (list)
Subject: Analyst Reports - GRC PD & Alternate PD

An administrative law judge issued a proposed decision (PD) and President Peevey issued an alternate proposed decision (Alternate PD) for PG&E's General Rate Case (GRC) yesterday afternoon. Following the releases, a number of analysts published reports commenting on the PD and Alternate PD. While analysts are relieved to see the proposals released, they feel that overhang associated with the uncertainty about the CPUC's direction and the San Bruno accident will continue to weigh on the stock, as illustrated by the Deutsche Bank report.

For your reference, the reports mentioned above are attached.

Lisa

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Lisa Lam

PG&E Investor Relations

One Market Plaza, Spear Tower, 2400

San Francisco, CA 94105

(415) 817-8137

From: Cherry, Brian K

Sent: 2/23/2011 3:58:04 PM

To: Michael R. Peevey (michael.peevey@cpuc.ca.gov) (michael.peevey@cpuc.ca.gov); Brown Carol (cab@cpuc.ca.gov) (cab@cpuc.ca.gov)

Cc:

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San Francisco, CA 94105

(415) 817-8137

From: Cherry, Brian K
Sent: 1/27/2011 12:46:34 PM
To: 'mp1@cpuc.ca.gov' (mp1@cpuc.ca.gov)
Cc:
Bcc:
Subject:

Nancy asks if you have any names you would recommend. You can call her directly if you'd like.

From: Peevey, Michael R.
Sent: 1/27/2011 12:12:17 PM
To: Cherry, Brian K (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=BKC7); Brown, Carol A. (carol.brown@cpuc.ca.gov)
Cc:
Bcc:
Subject: RE: Analyst Report - J.P. Morgan Downgrade

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To: Peevey, Michael R.; Brown, Carol A.
Subject: Fw: Analyst Report - J.P. Morgan Downgrade

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One Market Plaza, Spear Tower, 2400

San Francisco, CA 94105

(415) 817-8137

From: Cherry, Brian K
Sent: 1/27/2011 12:07:52 PM
To: 'mp1@cpuc.ca.gov' (mp1@cpuc.ca.gov); 'cab@cpuc.ca.gov' (cab@cpuc.ca.gov)
Cc:
Bcc:
Subject: Fw: Analyst Report - J.P. Morgan Downgrade

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PG&E Investor Relations

One Market Plaza, Spear Tower, 2400

San Francisco, CA 94105

(415) 817-8137

From: Clanon, Paul
Sent: 1/26/2011 5:08:31 PM
To: Cherry, Brian K (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=BKC7)
Cc:
Bcc:
Subject: RE:

Wait, now I have to be interrupted
with your cockamamie ideas while I'm trying to get two new
Commissioners ready
for tomorrow, and preparing myself to testify in Senate Budget tomorrow,
and
YOU'RE SITTING ON A FUCKING BEACH IN KAUAI??

-----Original Message-----
From: Cherry, Brian K
[mailto:BKC7@pge.com]
Sent: Wednesday,
January 26, 2011 5:04 PM
To: Clanon, Paul
Subject:

Paul - I
understand TURN and CCSF both filed separate motions for a San Bruno
investigation. I am assuming that given the IRP, the NTSB and the soon to be
issued OII (speculation on my part) that you have enough on your hands and
that
these petitions don't really add to the debate. At least that is my take
sitting
on the beach in Kauai trying to enjoy my vacation !

From: Cherry, Brian K
Sent: 1/21/2011 12:55:55 PM
To: mp1@cpuc.ca.gov (mp1@cpuc.ca.gov); Brown Carol (cab@cpuc.ca.gov) (cab@cpuc.ca.gov)
Cc:
Bcc:
Subject: FW: UBS on PCG: CPUC End Game Begins

FYI

From: jim.vonriesemann@ubs.com [mailto:jim.vonriesemann@ubs.com]
Sent: Friday, January 21, 2011 12:31 PM
Subject: UBS on PCG: CPUC End Game Begins

Attached for your consideration are our latest thoughts on PG&E and the California PUC.

As always, call with questions.

Best,

Jim von Riesemann

CPUC End Game Begins

□ Senate fails to act on confirming Commissioner Ryan
We confirmed with the CPUC that Commissioner Ryan was not confirmed by the California Senate by the statutory deadline of January 20, 2011. This now leaves the five person CPUC in a two member, non-quorum position.

□ Governor Brown now has three appointments to make
Gov. Brown will now have three nominees to the CPUC, none of whom are known at this time. Our working assumption is that Gov Brown will want to have his nominees with him during the 100 year anniversary celebration of the CPUC, which is on January 27. We hope the new CPUC will continue to equitably balance consumer and shareholder interests; we believe Chairman Peevey has done just

that and has been a stabilizing balance on the commission.

□ Settlement decision delayed; cost of capital formula coming into focus
At a minimum, we believe there will be a further delay in rendering a decision in PCG's pending GRC settlement. In addition to the quorum issue, our view is the CPUC will need at least an additional month to "get up to speed" on this proceeding. Separately, the makeup of the CPUC commissioners could influence the cost of capital formula which was sanctioned and administered by the CPUC

and is due for re-examination in mid-2012.

□ Valuation – Fairly valued at current levels; Maintain Neutral rating
Our $49 target price remains intact, and is derived using a combination of P/E, DDM, and DCF

valuation methodologies.

Jim von Riesemann
Executive Director
UBS Investment Research
1285 Avenue of the Americas
New York, New York 10019
(212) 713-4260 tel
(347) 852-2291 mobile
email: jim.vonRiesemann@ubs.com

Julien Dumoulin-Smith
Equity Research Analyst
Electric Utilities & IPPs Group
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Email: julien.dumoulin-smith@ubs.com

David Eads
Associate Analyst
Electric Utiltiies
(212) 713-3630
Email: David.Eads@ubs.com

From: Cherry, Brian K

Sent: 1/21/2011 12:55:55 PM

To: mp1@cpuc.ca.gov (mp1@cpuc.ca.gov); Brown Carol (cab@cpuc.ca.gov) (cab@cpuc.ca.gov)

Cc:

Bcc:

Subject: FW: UBS on PCG: CPUC End Game Begins

FYI

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Sent: Friday, January 21, 2011 12:31 PM
Subject: UBS on PCG: CPUC End Game Begins

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Best,

Jim von Riesemann

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- **Valuation – Fairly valued at current levels; Maintain Neutral rating**

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Jim von Riesemann
Executive Director
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Email: julien.dumoulin-smith@ubs.com

David Eads
Associate Analyst
Electric Utiltiies
(212) 713-3630
Email: David.Eads@ubs.com

From: Cherry, Brian K

Sent: 1/20/2011 3:17:30 PM

To: mp1@cpuc.ca.gov (mp1@cpuc.ca.gov); Brown Carol (cab@cpuc.ca.gov) (cab@cpuc.ca.gov)

Cc:

Bcc:

Subject: FW: Analyst Reports - Deutsche Downgrade & BofA-ML Manzana and California Updates

Mike/Carol - FYI.

From: Lam, Lisa
Sent: Thursday, January 20, 2011 3:10 PM
To: Officers of PG&E Corporation; Officers of Pacific Gas and Electric
Cc: Investor Relations (list)
Subject: Analyst Reports - Deutsche Downgrade & BofA-ML Manzana and California Updates

This morning analysts issued three reports discussing PG&E: a downgrade from Deutsche Bank; a summary of a Wall Street meeting with Commissioner Simon from Bank of America – Merrill Lynch; and an update on the Manzana project, also from BofA – Merrill.

Jonathan Arnold of Deutsche Bank downgraded PCG stock from "BUY" to "HOLD" given uncertainties over the composition of the Commission, and the assumption that PG&E's authorized ROE, currently at 11.35%, will be lowered by 70 basis points beginning in 2013. Arnold believes continued negative press surrounding the San Bruno accident and NTSB investigation could drive further political and regulatory pressures on the company.

Arnold cited possible upside risks including no ROE or equity adjustment in 2013 and no major change in the regulatory tone and direction. He also presented the following potential downside risks for PG&E: (1) disallowance or disapproval of spend for capital projects necessary to grow rate base and earnings; (2) an earlier ROE adjustment if interest rates continue to decline; (3) an increase in cost sensitivities from customers which could impede growth plans; and (4) the inability to recover costs associated with the San Bruno accident.

Steve Fleishman of Bank of America – Merrill Lynch issued two reports today, (1) a summary of yesterday's Wall Street Utility Group meeting with Commissioner Simon in New York and (2) a note on the status of the Manzana wind project. In both notes, Fleishman concluded that current investor concerns about California could be overblown; Fleishman remains supportive of California.

In the Wall Street meeting, Commissioner Simon pointed out that he expects Peevey will likely remain President of the CPUC, which Fleishman views as key given the consistent influence Peevey has provided the Commission. While PG&E remains in the media headlines, Fleishman does not expect this overhang to impact the GRC settlement. Fleishman believes, given California's weak economy and 12.4% unemployment rate, at least one of the new commissioners could focus on job creation, specifically jobs tied to utilities' infrastructure spend. He also noted an expectation that a slight reduction could be made to the authorized ROEs for California IOUs post 2012.

In his report on Manzana, Fleishman stated that PG&E filed a motion with the CPUC on January 19 to withdraw the Manzana wind project application after Iberdrola exercised its option to terminate the purchase and sale agreement. Fleishman does not believe investors should view the Manzana termination as a surprise given the CPUC Proposed Decision to deny the project, and assumes PG&E will require less equity in 2011 as a result.

In trading today, PCG closed down 0.7% at $47.00, compared to the average comparator group company, which was up 0.4%. The S&P 500 was down 0.1%, and the Dow Jones Utility Average was up 0.6%.

For your reference, the full reports are attached.

Lisa

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Lisa Lam

PG&E Investor Relations

One Market Plaza, Spear Tower, 2400

San Francisco, CA 94105

(415) 817-8137

CREDIT SUISSE

Power and Electric Utilities:

California Utilities Trip Questions/Info Pack

September 30 – October 1, 2013

Research Analysts:

Dan Eggers, CFA (212) 538-8430, (646) 416-2080 (M)
Kevin Cole, CFA (212) 538-8422
Matthew Davis (212) 325-2573

California Trip Outline

2013 California Trip

	Monday, September 30	Tuesday, October 01	Wednesday, October 02	Thursday, October 03
7:00 AM	[redacted]	[redacted]	[redacted]	[redacted]
7:30 AM				
8:00 AM		Travel to SRE 8.15-8.45	Travel to SED 8.00-8.30	
8:30 AM				
9:00 AM		SRE 9.00-10.45 AM	SED Dir Hagan 8.45-9.15 AM; Travel to CPUC	
9:30 AM			Comr Peterman Chief of Staff 9.30-10.00 AM	
10:00 AM			CPUC Exec Director Clanon 10.00-10.30 AM	
10:30 AM			Break	
11:00 AM		Travel to SF 12.20 PM flight, landing at 1.50 PM	Comr Florio Chief of Staff 11.00-11.30 AM	
11:30 AM			DRA Acting Dir Como 11.30-12.00 AM	
12:00 PM			Travel to TURN	
12:30 PM			TURN Exec Director Toney 12.15-12.45 PM; Travel to PCG	
1:00 PM			PCG 1.00-3.00 PM	
1:30 PM				
2:00 PM				
2:30 PM				
3:00 PM	EIX 3.00-5.00 PM		[redacted]	
3:30 PM		Comr Ferron 3.30 - 4.00 PM		
4:00 PM				
4:30 PM				
5:00 PM	Travel to SD			
5:30 PM				
6:00 PM		Dinner - 6pm, table for 13 MKT Restaurant - Bar San Francisco Four Seasons		
6:30 PM				
7:00 PM				
7:30 PM				
8:00 PM				
8:30 PM	Dinner - 8:30pm, table for 11 Grant Grill US Grant Hotel			

Meeting Attendee Information

Group	Name	Title	Date	Time
Regulatory				
Comr Ferron's Office (CPUC)	Mark Ferron	Commissioner	10/1/13	3.30 - 4.00 PM
Comr Peterman's Office (CPUC)	Julie Fitch	Chief of Staff	10/2/13	9.30-10.00 AM
	Jennifer Kalafut	Senior Energy Advisor		
Comr Florio's Office (CPUC)	Marcelo Poirier	Senior Legal Advisor	10/2/13	11.00-11.30 AM
	Rachel Peterson	Senior Energy Advisor		
CPUC	Paul Clanon	Executive Director	10/2/13	10.00-10.30 AM
Safety and Enhancement Div.	General Hagan	Executive Director	10/2/13	8.45-9.15 AM
	Elizaveta Malashenko	Deputy Director		
Division of Ratepayer Advocates (DRA)	Joe Como	Acting Director	10/2/13	11.30-12.00 AM
	Linda Serizawa	Deputy Director for Energy		
	Michael Campbell	Program Manager		
	Chris Ungson	Project and Program Supervisor		
The Utility Reform Network (TURN)	Mark Tooney	Executive Director	10/2/13	12.15-12.45 PM
Corporate Attendees				
Edison International (EIX)	Jim Scilacci	EVP and CFO, Edison International	9/30/13	3.00-5.00 PM
	Ron Litzinger	President, Southern California Edison		All in one meeting
	Linda Sullivan	SVP and CFO, Southern California Edison		
Sempra Energy (SRE)	Jessie Knight Jr.	CEO SDG&E	10/1/13	9.00-9.30 AM
	George Liparidis	President & CEO, Sempra International		9.30-10.00 AM
	Anne Smith	CEO, SoCalGas		10.00-10.45 AM
Pacific Gas and Electric (PCG)	Tony Earley	Chairman, CEO and President, PG&E Corp	10/2/13	1.00-2.00 PM
	Kent Harvey	SVP and CFO, PG&E Corp		
	Tom Bottorff	SVP, Regulatory Affairs		
	Dinyar Mistry	VP, CFO, and Controller, PG&E		
	Chris Johns	President, PG&E	10/2/13	2.00-3.00 PM
	Nick Stavropoulos	EVP, Gas Operations		
	Geisha Williams	EVP, Electric Operations		
	Fong Wan	SVP, Energy Procurment		
	Gabe Togner	VP, Investor Relations, PG&E Corp	10/2/13	1.00-3.00 PM
	Sara Cherry	VP, Investor Relations, PG&E	10/2/13	1.00-3.00 PM

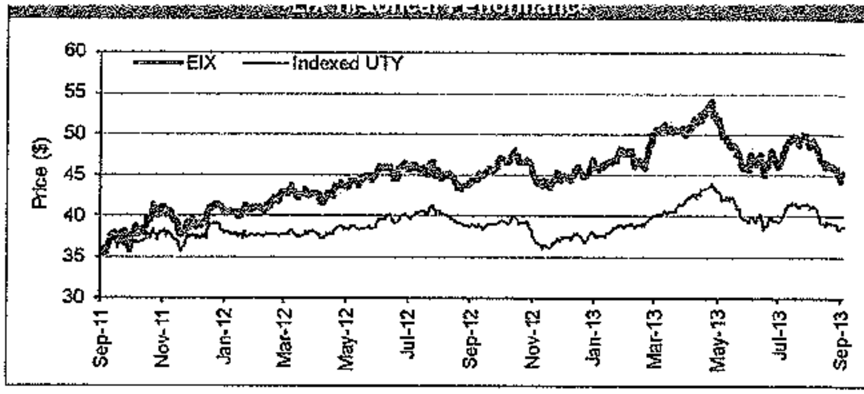
Credit Suisse Hotel Information

Hotel Accommodations
Night 1 - San Diego The US Grant Hotel 326 Broadway, San Diego, CA 92101 Phone: 619-232-3121 http://www.usgrant.net/
Night 2 - San Francisco Four Seasons Hotel San Francisco 757 Market Street, San francisco, CA 94103 Phone: 416-633-3000 www.fourseasons.com/sanfrancisco

Edison International (EIX)

Target Price	53.00	Rating	Neutral

	2013	2014	2015
PS	3.35	3.52	3.50
BITDA	3,925	4,232	4,405
P/E	13.6x	12.9x	13.0x
EV/EBITDA	6.2x	5.7x	5.5x
Reg Avg P/E	15.3x	14.4x	13.8x
Reg Avg EV/EBITDA	8.9x	8.7x	8.5x



Source: CS Estimates, Factset as of 09/09/13

Current Market Statistics			
Price	45.47	Dividend Yield	3.0%
Market Cap	14,857	Payout Ratio	40%
EV	24,144	Buy/Hold/Sell	65%/30%/5%

Performance Comp	3 mo	6 mo	12 mo	24 mo
EIX	-3.4%	-10.3%	2.6%	28.6%
Rel to UTY	-0.4%	-6.7%	3.1%	18.9%
Rel to S&P	-5.1%	-17.7%	-13.6%	-16.2%

SONGS (San Onofre Nuclear Generating Station).

- **Update on the current status of the SONGs OII and CPUC treatment of SONGS recovery.** Walk through the timing of the various OII phases and major drivers in each. Considering the CPUC's recent track record what is a realistic goal for resolution (Phase 1 decision targeted 4Q13, Phase 2 for February 2014, Phase 3 not specified)?
  - How will the Phase 2 process work as it relates to asset adjustments to rate base and O&M costs? What will be the assessment criteria and how important is a determination of error be (aka MHI's modeling error versus SCE errors on failure to completely model, choice of vendor, etc)?
  - How will the NRC's determination that MHI's modeling was flawed impact determinations on the OII proceedings?
- Of the $2.1 BN of total net investment, you have now impaired $575 MM.
  - **What would cause you to change the size of the impairment** before a final decision from the CPUC?
  - How should we think about equity funding needs depending on size of the ultimate impairment and ongoing earnings / recovery potential for the net investment that is not impaired?
- Discuss the implications of excess purchased power costs being pulled out of rates and process to determine recovery.
- Now that the retirement decision has been made and Certification of Permanent Cessation of Power Operations submitted to the NRC starting the decommissioning process, what are the risks of additional earnings drags or charges ahead of the next GRC process; which costs could be most at risk?
- **President Peevey encouraged parties to reach a settlement on SONGS recovery.** Where are those talks and is a deal possible or have parties been conditioned by the San Bruno incident to keep demanding more?
- **Can you realistically find resolution** – either settlement or CPUC approval – **before you have resolved recovery from MHI and NEIL** considering how much money is prospectively in play? Can you draw a precedent from the California energy crisis where eventual recoveries were returned to customers years later?
  - MHI warranty recoveries beyond the $138 MM warranty cap. What is happening with the non-binding negotiations after SCE filed the formal Notice of Dispute on July 18th? Is there a realistic opportunity to settle or will you need to go through binding arbitration (and how long would this take)? Even after arbitration, are there other legal recourse options if the parties don't like the outcome?
  - Explain the process for seeking NEIL insurance recovery and what would lead you to request capital recovery (due by 12/31/13) in addition to the excess purchased power costs you have currently filed. We hear some debate about whether equipment not working properly is an 'insurance' event like the major damage incurred at Crystal River 3; explain how SONGS qualifies and similarities to the CR3 situation?
- What precedents exist for segregating economic exposure: either impair the plant or deny recovery of fuel but not both (because if you take a hit on the plant then there should not have been a fuel cost shortfall or vice versa?).
- When will costs for maintaining SONGS move over to funding from the decommissioning trust fund rather than in base SCE rates?
- What is the outlook for system reliability in Southern CA considering SONGS retirement and reserve margin pressure? Would SCE consider building / owning any needed replacement generation and locationally is there a good place to build a new plant?

SCE Rate Case and targeted 1/1/15 implementation

- Discuss the main drivers of the higher than expected capex plans proposed in the July 2013 pre-filing.
- How does the composition of proposed capex compare to recent spending programs (less transmission)? How do you make the case for elevated infrastructure replacement (up 120% from last case, over half of projected spending) in a slow demand growth environment?
- SCE will over-earn in 2013-'14 since the cost cuts implemented while waiting on a GRC decision were deeper than what the case provided. Does this create risk in the next GRC as the CPUC either (a) looks for direct or indirect claw back of the excess savings or (b) the CPUC will be more skeptical of your projected O&M costs since you were able to find so much more savings in this rate cycle, creating earned ROE risk in the next cycle?
- What are the prospects for further O&M savings after the big push for 2012-14?
- What is the outlook for magnitude of rate increases based on GRC filing and contracted renewable generation additions?
- What can SCE do to help move along the GRC process to get a decision closer to 1/1/15 relative to the massively late decision last cycle? Can you resolve the GRC with SONGS potentially still in process?

Walk through the details of the FERC settlement process and the ultimate outcome that, which while lower than previously allowed, seemed to be a fair and reasonable result in an era of continued transmission ROE pressure.

What are the implications of AB 327 that changed the net metering rates such that compensation for rooftop solar would be based on actual avoided utility costs rather than retail rates? Do you expect a slowdown in rooftop residential solar that has arguably been a transfer of customer funds to high income customers who could afford the capital investment in solar?

Edison Mission.

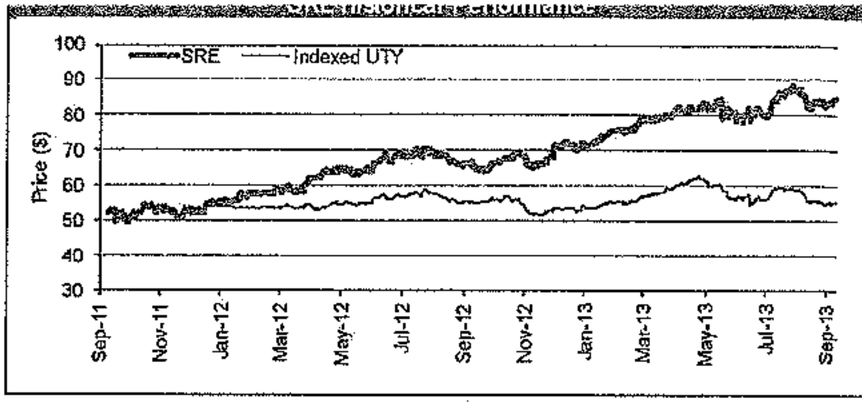
- Provide an update on the bankruptcy process and implications of the creditors' termination of the Transition Support Agreement (TSA).
- **The creditors have made some high economic demands of EIX; discuss EIX's position and how long realistically will this take to resolve?** Can you better explain the creditor position and how they can make the argument against EIX for such significant losses?
- Discuss the status of any potential worthless stock deductions from your equity stake in Edison Mission and when you will know if there is value in this asset?

..vidend policy. How should we think about the path for growing the dividend to the 45-55% payout ratio on SCE earnings; with higher planned SCE capex and SONGS uncertainty, how do you get comfortable with a bigger '13 increase after opting for a smaller increase last year? With increased CPUC scrutiny of SONGS cost recovery, will the politics preclude you in some way from pursuing a bigger increase?

Sempra Energy (SRE)

Note: SRE is not currently covered by Credit Suisse

	2013	2014	2015
EPS	4.32	4.50	4.50
EBITDA	3,176	3,359	3,652
P/E	19.7x	18.9x	18.9x
EV/EBITDA	10.4x	9.8x	9.0x
Reg Avg P/E	15.4x	14.5x	13.9x
Reg Avg EV/EBITDA	8.9x	8.7x	8.6x



Source: Factset as of 09/05/13

Current Market Statistics			
Price	85.14	Dividend Yield	3.0%
Market Cap	20,740	Payout Ratio	58%
EV	33,025	Buy/Hold/Sell	71%/29%/0%

Performance Comp	3 mo	6 mo	12 mo	24 mo
SRE	3.5%	6.0%	26.9%	56.6%
Rel to UTY	6.8%	10.1%	27.0%	51.7%
Rel to S&P	1.5%	-1.7%	12.9%	19.2%

General Regulatory Matters – Reiteration of 6-8% growth and 4-5% dividend growth?

SDG&E

- Thoughts on California regulatory process. What sort of changes can be made such that future General Rate Cases (GRC) are executed in a more timely fashion than what happened to SDG&E and SCE in the most recent cycle?
- How do you view the potential for future rate case/regulatory delays impacting the ongoing management of the business and how you make capex plans?
- **Do you expect to keep the rate base mix stable at the current ~62% CPUC / 38% FERC jurisdictional** (would be supported by the 2013-17 capex plan)? Do you see more risk to the CPUC or FERC capex program over the next 5 years?
- Status on transmission project approvals: South Bay Relocation (3Q13), South Orange County (2H14), Cleveland National Forest (2014)? Combined with ECO (substation already approved), how much do these projects account for of the $1.1 BN of targeted capex over the next 5 years? What else is in queue in case any of these projects do not move forward?
- Customer usage: What do you see for usage trends at different customer classes and how much efficiency do you view as realistic?

  What are the implications of AB 327 that changed the net metering rates such that compensation for rooftop solar would be based on actual avoided utility costs rather than retail rates? Do you expect a slowdown in rooftop residential solar that has effectively been a transfer of customer funds to high income customers who could afford the capital investment in solar?
- Where do you see the CA RPS going from here; is there room to go higher than 33% by 2020?
- **SONGS:**
  - What role did SDG&E have in the decision to shut down San Onofre Nuclear Generating Station (SONGS) and how involved are you in the proceedings/mediation with NEIL and Mitsubishi respectively?
  - **What recourse do you have against your partner SCE since they were the operator?**
  - Update on the SONGS OIIs and what the various scenarios could mean for SRE from a financial standpoint above and beyond the 2Q13 loss of $119 MM?
  - What options is SDG&E currently evaluating to help fill the generation void with the closure of SONGS? EIX owns 78%, SRE owns 20% and the City of Riverside owns the remaining 2% of Units 2 & 3?
- Updated thoughts on ability to earn at or above the authorized return at either or both SoCalGas / SDG&E.

SoCalGas

- **Thoughts on California regulatory process.** What sort of changes can be made such that future General Rate Cases (GRC) are executed in a more timely fashion than what happened to SDG&E and SCE in the most recent cycle?
- **Looking forward to the next rate case (2016 test year) what do you expect to be the major issues of focus?**
- The recent GRC decisions had a clear focus on managing costs and slowing the rate of inflation. The SRE utilities have a long history of being well run; where do you see opportunity to make the businesses run better? Can you manage within the inflation index numbers the CPUC approved?
- PSEP (pipeline safety enhancement plan) is expansive and will take a long time to complete - $1.7 BN for 2012-17, $1.4 BN for 2017-22, and another $1.5-3.0 BN to test and replace other pipe from 2017and beyond. As you are doing the work, what have been the big surprises and are you changing your work flow or rate of investment based on what you have seen so far? When do you expect to have more clarity on the $1.5-3.0 BN of long-dated investment?

What are you seeing for customer growth both with new construction and customer adoption of natural gas?

Note: SRE is not currently covered by Credit Suisse

SoCalGas Continued

- What are you seeing for uptake of CNG vehicles and does this create a growth opportunity?
- What sort of savings do you expect to realize from advanced meters (6 MM in total for $875 MM from 2010-17)?
- What is the risk of CPUC pushback against the projected 14-16% rate base growth? Are you finding a willingness to support this level of investment to support reliability / safety and what are risks that bills rise faster than you are currently projecting?

Cameron Natural Gas Export Facility

- Projected facility stats: SRE to retain 50.2% of equity, total cost of $9-10 BN ($6-7 BN to go), $750-875 MM of EBITDA to SRE, $300-350 MM of net income to SRE, leverage at 60-70%.
- You have suggested potential upside to the project with expansion opportunities. Discuss what those would be, how big, how much investment?
- Have there been any substantive changes to the FERC environmental study schedule? Do you still expect to receive FERC NEPA document in November and Section 3 authorization early in 2014? '
- When does SRE anticipate receiving DOE approval to export to non-FTA countries considering the recent Cove Point approval putting the Cameron Facility 1/2 in the current queue with the DOE?
- Any change to expected earnings contribution – Analyst day laid out $300-350 MM attributable to Sempra in the early years? **How do rising interest rates impact total project economics** (targeting 60-70% leverage) and are there carve-outs in the off-take agreements to adjust tariffs for financing costs?
- Progress on securing the EPC contract; is year-end still a feasible goal? What will we know about contracting terms, how much exposure the owners will have to development risk vs the EPC partners, and any impact on expected project economics?
- Updated discussion of SRE's view on their storage assets and ability to ascribe additional value through these assets and associated management of gas flow throughout the Gulf Coast region with LNG export now becoming a reality. What specific opportunities is SRE evaluating, what is the typical contract duration 1/3/5 years? How do Cheniere, Freeport and Lake Charles DOE non-FTA approvals impact timing? Update on LA Storage facility? Analyst day they said they were going to cut back the investment

ternational

- Is 30%/70% still the right mix between int'l vs domestic SRE businesses? Re-affirm cash repatriation levels of $200-300 MM.
- Mexico
    - **When should we expect to hear an announcement on phase 2 of Los Ramones** ($2 BN total projected investment). How do you assess your competitive position on this project considering you already won Phase 1? What would be the timing for this capex and how should we think about funding for the project – have suggested a JV partner, potential for more leverage, issue equity at IENOVA?
    - Sonora pipeline ($1 BN) targeted for in-service in 2H14. How is construction progress and level of confidence in project costs?
    - Update on opportunities for additional wind development (up to 1000 MW) and how will US policy decisions on extension of tax credits impact the development (will be more competitive if US developers do not have the subsidies)?
    - **How much capex activity can the Mexican operations functionally manage?** Is there a limit on how quickly investments can be executed for logistical reasons internally?
    - What is the process for making a decision on LNG exports from ECA (Energia Costa Azul)? Are there limitations on natural gas sourcing considering the significant Mexican domestic demand? What sort of contract renegotiating would be necessary since the project is currently contracted until 2028 as an LNG import facility?
- IENOVA IPO has done very well (stock from 34 to 52 this year). **Do you see an opportunity to do something similar with Chilquinta** where you own 100% of the equity? Is there need for a certain level of earnings contribution before you would look to pursue a public float or is it more an issue of needing the capital for a specific project?
- Update on Argentina sale; any change since last quarterly call?
- Given all the talk about the additional growth projects and needed infrastructure at the South American Utilities, is 6-8% growth still the right band; what would SRE need to see in order to increase the range?
- Walk through the repatriation mechanics and the various tax implications across the various jurisdictions.

Sempra Energy (SRE) Continued

Note: SRE is not currently covered by Credit Suisse

International Continued

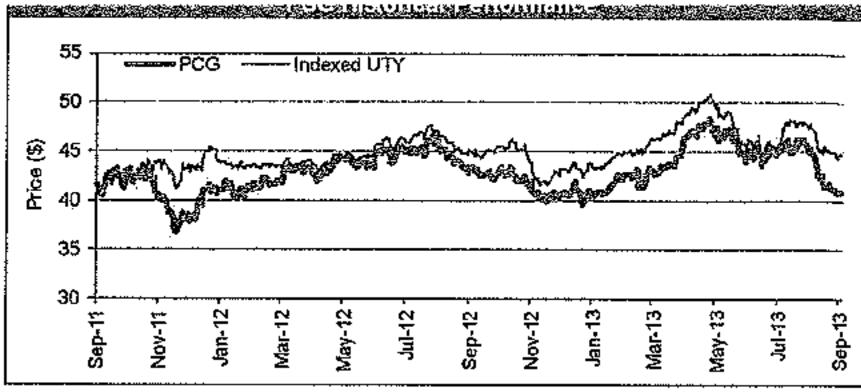
Updated thoughts on potential wind/solar installations; currently do not have any additional wind guidance? Are there other partnerships that SRE is looking at similar to what was executed with ED earlier this year? How has the market appetite been for structures similar to this?

- MLP
  - Where are you in the MLP planning process? Do you need to have all of the Cameron approvals in place before you decide to move forward?
  - How much distributable cash will be needed from the starting MLP base to have a successful standalone business?
  - How will you plan to structure ownership and design of a GP interest to be help at SRE?

PG&E Corp (PCG)

Target Price	50.00	Rating	Neutral

	2013	2014	2015
EPS	2.66	3.10	3.26
EBITDA	4,587	5,228	5,580
P/E	15.4x	13.2x	12.6x
EV/EBITDA	7.1x	6.2x	5.8x
Reg Avg P/E	15.3x	14.4x	13.8x
Reg Avg EV/EBITDA	8.9x	8.7x	8.5x



Source: CS Estimates, Factset as of 09/09/13

Current Market Statistics			
Price	40.99	Dividend Yield	4.4%
Market Cap	18,346	Payout Ratio	69%
EV	32,499	Buy/Hold/Sell	39%/61%/0%

Performance Comp	3 mo	6 mo	12 mo	24 mo
PCG	-8.9%	-4.6%	-5.7%	0.8%
Rel to UTY	-6.0%	-1.0%	-5.2%	-8.9%
Rel to S&P	-10.7%	-12.0%	-22.0%	-44.0%

San Bruno

- Walk through the current anticipated timeline for an ALJ decision proposal and ultimately a Commission final decision for the 3 OIIs. **How has the ALJ's request for additional information on PCG's ability to raise capital and the other misc. filing date extensions impacted the timeline laid out on the 2Q call?** Given the complexity of the issue(s) (i.e. 3 OIIs combined into 1 decision, numerous involved parties, etc.) what is the risk that the case does not get resolved before year end?
- **Further discussion/clarification of PCG's main arguments against the Amended CPSD Fine/Remedy proposal, namely** (a) reasoning why any penalty "must" go to the General Fund, (b) why previously recoverable PSEP I should not be disallowed when the CPUC stated that the decision in the PSEP proceeding (R.11-02-019) was subject to refund pending the findings of the OII, and (c) further clarification of the Overland Report $2.25 BN threshold level interpretation which CPSD claims is only forward looking in terms of disallowed costs (PCG states that Overland includes prior unrecovered costs in the $2.25 BN).
- **Discuss the 2 orders to show cause (OSC) issued by the CPUC on Aug 19th and how PCG came to find the errors in its pipeline recordkeeping?** How did these errors occur in a world of greater internal focus after San Bruno and what changes are incrementally being made? What are the initial thoughts about different financial implication scenarios? Could this impact the San Bruno OIIs? Is this legally possible given the OII record is currently closed? Has there been talk of re-opening the record resulting in further delays? Are there operational implications for the gas pipeline system if held to lower operating pressures?
- Projected costs to cover encroachment issues (where pipeline rights of way have not been maintained) were estimated at $500 MM; after more time to evaluate, how comfortable are you with that cost estimate? As you better evaluate the overall system (beyond encroachment), are **you discovering other issues that have been looked over that will require unplanned capex?**
- **Potential risk of a federal criminal complaint (5 year statute of limitations) after CA just passed on a case?** What would be the basis for determination as a criminal act and what would be the implications for the company, current management, and former management?
- Of the $565 MM of third party claims that have been now settled, how much is or will be covered by insurance proceeds? How much insurance has been recovered so far?

General Regulatory Case

- **Update on the status of the 2014 General Rate case.** What has the initial CPUC commentary/reaction been to the proposed $1.25 BN revenue increase, especially in light of the recent developments in the Pipeline Safety OIR?
- What was the tone of the discussions at the first settlement conference; is settlement a feasible option prior to San Bruno resolution? What gives you confidence this case can get done close to 1/1/14?
- How inter-related is the need to resolve San Bruno before resolving the rate case?
- **Can you earn your allowed ROE?** With PG&E's focus on improving performance to 1st / 2nd quartile and the CPUC leaning on O&M costs in SCE and SDG&E cases, is there risk you under-earn in next GRC cycle? What sort of O&M flexibility do you anticipate beyond 2013 relative to what you plan to spend in 2013? What is the natural rate of cost inflation for your business?
- What is outlook for rate and bill inflation over the next GRC period based on requested rate increases and the impact of further share gains for renewables to meet the 33% standard?

Research Analysts: Dan Eggers, CFA (212) 538 8430 dan.eggers@csg.com
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Other Issues

- **What caused the change in tone in August to bring up risk of bankruptcy and concerns about your ability to raise capital so late in the San Bruno process particularly after such a significant transfer of capital from shareholders already?** How was the response to the comments and did it have any noteworthy impact considering how successful PCG has been in raising debt and equity capital over recent years?
- Where does the request for re-hearing on the outstanding TO14 issue stand for FERC regulated transmission assets (PCG was required to re-file with the FERC using an ROE of 9.1% based on the group median, rather than their previously approved 11.35%)? What is the path to resolution and expected timeline: weeks, months or more?
- **Utility performance improvement.** What is the expected timing to get to 1st / 2nd quartile operating performance at the utilities and what have you done to turn around performance? What impact does this focus on better performance have on future O&M cost inflation?
- What are the implications of AB 327 that changed the net metering rates such that compensation for rooftop solar would be based on actual avoided utility costs rather than retail rates? Do you expect a slowdown in rooftop residential solar that has effectively been a transfer of customer funds to high income customers who could afford the capital investment in solar?
- **Thoughts on timing of equity issuance** through 2013 and beyond with $562 MM being issued earlier this year. Does the $1.0-1.2 BN estimate provided on the 2Q13 call still hold true. Is there a realistic potential fine amount or additional unrecoverable cost that could lead to more equity? Depending on outcome (more denial of recovery on future PSEP spending), would you be able to spread out timing of equity issuance and meet future needs using DRIP and DRIBBLE programs?

California Regulatory Topics of Interest

Regulatory Performance

- **Recent rate cases have taken considerably longer than planned**, creating great uncertainty with the companies to manage capex and costs as well as the investment community. California has a long history of innovative regulatory designs that other states should replicate; how does the Staff and Commission not squander the benefits and goodwill of constructive regulatory design?
- Recent GRCs have had a clear focus on managing O&M costs lower as a way to limit rate increases. **How does the CPUC balance cost management while keeping a closer eye on utility performance** to avoid the deficiencies seen with San Bruno and broader PG&E poor operational performance?
- Several utilities appear to be earning above their allowed ROEs during the current GRC rate cycle. **How does the CPUC think about overearning against plans provided by the utilities** (that are generally then awarded at levels lower than originally requested by the utilities) and how will the success in managing costs this cycle factor into cost assumptions in future cases?
- **Reviews of PG&E's problems also indicated a level of oversight deficiency by the Commission as well. What changes are being made institutionally the CPUC to address this?**
- San Bruno was clearly a unique and tragic event, but the economic costs discussed to be levied against PG&E are objectively disproportionate to the investment made in the business (and impossible to fund but for the size of the entire PG&E corporation). Not speaking specific to PG&E's case, but more broadly how does the CPUC philosophically approach the regulatory construct that Utilities deserve to earn a fair return on prudently invested capital in exchange for providing safe, reliable, low cost service? **What are the risks to future investment in the state** – by the utilities and with money from investors – **if market participants are limited on the upside to the allowed returns on investment while the downside could be materially significant to total investment in the business?**

Renewable Energy Portfolio Standards (RPS)

- With the passage of A.B. 327, California Public Utility Commission (CPUC) has the ability to raise the RPS target beyond the 33% for 2020.
  - How aggressively does CPUC plan to proceed with more renewables? Can the system manage a higher mix?
  - By 2020, does the CPUC envision the energy efficiency portion of the standard to be maximized?
  - With Palo Alto's municipal utility approving 80 MW of solar PV projects with a PPA of 6.9 cents/kWh, how much will the focus after 2020 will be on using low cost energy to meet the RPS? Would this approach slow the RPS growth rate?

  The Green Tariff Shared Renewables Program (S.B. 43) was passed by the assembly and the Senate in mid-September. It allows businesses and individuals to purchase shares in renewable energy developments of three investor-owned utilities overseen by the CPUC.
  - How will you decide which clean energy projects qualify for the program?
  - Will the projects be dependent on location?
  - Will T&D upgrades be part of the selection process? Will they include transmission asset construction?
- Effect of RPS on distribution system design:
  - The governor has a goal of 12 GW of distribution generation installed by 2020 as part of the RPS standards. How is CPUC incorporating this requirement into the design of the distribution system?
  - A.B. 327 requires investor-owned utilities to submit distribution plans in utility general rate cases. How will distributed generation play into overall approved distribution spending?
  - How does the CPUC plan to address the growing Utility concern / opposition to distributed generation and the apparent subsidization that accompanies the model?
  - Recently, what's the thinking on distribution design to support renewable energy zones?

Transmission Planning

- By the end of the year, the California Energy Commission (CEC) is going to identify renewable energy zones across California. How will these renewable energy zones play a role in transmission planning?
- How do you balance the desire to move more towards clean energy via electric vehicles with the potential need for added generation and recovery of the associated costs?
- On September 16, 2013 Cal ISO released its 2014-16 strategic plan with three goals: 1) leading the transition to renewable energy and advanced energy storage, 2) maintaining reliability during industry transformation, and 3) leading global collaboration.
- How will California most efficiently go about transforming the grid from a one-way distribution system to a two-way distribution system?

  How would rate design be used to the address the natural generation cycle of renewables?

California Regulatory Topics of Interest

Rate Design

- Time-of-Use rates are an area the Commission discussed at a recent workshop.
    - What do you view as the most effective rate design; Flat, Tiered, TOU (time of use), green option, fixed charges?
    - How do you view the most optimized structure for residential customers across the various geographies / demographics / usage patterns?
    - How do you intend to use rate design to help meet the state energy efficiency, demand response, and renewable energy portfolio standards?
    - How is the electrification of transportation going to impact retail rate design?

Cap-and-Trade (AB32)

- The CPUC voted to distribute the utility sector's carbon allowance revenues with 15% of the proceeds for Green House Gas (GHG) reduction programs and the remaining 85% as a biennial "climate dividend."
- Why was this approach taken? Why wasn't more reinvested in reduction programs?
- It appears that the California and Ontario cap and trade markets will be linked at the beginning of 2014. How will the combination of the Quebec and California cap and trade markets affect carbon allowance revenues?
- **How does the state resolve the caps on CO2 emissions against ongoing plans to build new CCGTs that will not be in compliance with the emissions rules well before the end of useful life?** How will the CPUC treat utilities that built these assets into rate base and will be exposed to future impairments?

Natural Gas

- There has been discussion about building a more robust natural gas infrastructure system in order to backup renewable energy.
    - What type of system-wide planning would take place?
    - How would the CPUC coordinate with CAISO?
    - What types of cost recovery vehicles would be used?
- Since there is a general sentiment in California backing the need to shift toward electrification, what types of policies would be implemented to support this shift?
- Natural gas pipeline safety has been a key area of focus since the San Bruno incident. Several decisions have come out that appear to be a direct result.
    - In Decision 11-06-017, the Commission declared an end to historic exemptions from pressure testing for natural gas transmission pipeline and ordered all California natural gas transmission pipeline operators to prepare Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test. **How does the Commission anticipate better monitoring the various utilities to ensure the appropriate level of recordkeeping accuracy is maintained,** and how does the Commission anticipate handling future gaps in the records of its 3 IOUs?
    - The Commission required the Southwest Gas Corporation to enact its Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan, to replace 7.1 miles of natural gas pipeline in its Victor Valley natural gas transmission system, and add a remote controlled shut-off valve to its Harper Lake natural gas transmission system. The cost of the pipeline replacements will be shared between ratepayers and shareholders, and the costs of the shut-off valve will be included in revenue requirement. Going forward will this be the Commission's approach?

Nuclear Power

- Southern California Edison (SCE) announced June 7, 2013 that it will permanently retire Units 2 and 3 of its San Onofre nuclear plant. How will the commission be involved in addressing the capacity shortage? What are the reliability concerns you are addressing? How do you intend to address the grid stability issues?
- Diablo Canyon Power Plant (DCPP) is the last nuclear power plant in California (operated by PCG). The NRC is currently reviewing the application for renewal.
    - Since nuclear DCPP is strategically located but is not critical for grid stability, if the NRC does not extend its nuclear operating license how would its decommissioning plan differ from SONGS?
    - What approach are you going to take to cost recovery for any once through cooling upgrades? Would it differ if the upgrades were not recommended by the Diablo Canyon Independent Safety Committee?
    - What is the backstop plan if DCPP cannot extend its nuclear operating license?

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California Regulatory Topics of Interest

Once Through Cooling (OTC)

- The goal of banning OTC is to protect marine and estuarine life without disrupting the critical needs of the state's electrical generation and transmission system. What has been the main point of resistance from the various involved parties?
- Currently, very few plants are incompliance. Under the current CPUC directive, what would be the penalty for a plant not being in compliance by the targeted deadline?
- Does California have a market-based competitive mechanism for evaluating which of these resources could be upgraded cost-effectively and which should retire because lower-cost alternatives exist? If a plant eliminated OTC, how will the costs be recovered?

Cyber-security

- With the modernization of the grid, how is California currently looking at addressing cyber-security?

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Regulated Utilities

(Dollars in millions, except per share amounts)

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Companies	Ticker	Rating	Price	Rate of Return	Target Price	Total Return Potential	Shares 2013E	Market Cap	Net Debt 2013E	Enterprise Value	Dividend Yield 2013E	Dividend Payout 2013E
American Electric Power	AEP	O	43.79	11.1%	53.00	25.4%	488	21,302	18,958	40,260	4.4%	60%
American Water Works Co	AWK	N	40.74	9.0%	45.00	13.1%	179	7,281	5,815	13,097	2.7%	49%
Black Hills Corp	BKH	O	49.40	3.2%	49.00	2.5%	44	2,192	1,437	3,623	3.3%	64%
CMS Energy Corp	CMS	O	26.37	11.2%	32.00	25.2%	272	7,169	7,416	14,585	3.9%	62%
Centerpoint Energy	CNP	R	24.00	R	R	R	R	R	R	R	R	R
Dominion Resources	D	O	62.49	8.9%	65.00	7.7%	579	36,126	23,401	59,527	3.6%	67%
DTE Energy	DTE	O	66.55	11.0%	78.00	21.1%	175	11,655	8,088	19,742	3.9%	64%
Duke Energy	DUK	O	67.26	10.5%	79.00	22.1%	705	47,420	43,056	90,476	4.6%	71%
Consolidated Edison	ED	U	55.78	9.3%	60.00	17.4%	295	16,433	11,592	28,055	4.4%	64%
ITC Holdings Corp	ITC	N	93.06	9.2%	94.00	2.7%	52	4,823	3,599	8,428	1.7%	33%
NV Energy Inc	NVE	N	23.57	1.4%	23.75	4.0%	237	5,595	4,619	10,213	3.2%	57%
PG&E Corp	PCG	N	41.87	10.1%	50.00	23.8%	446	18,740	14,153	32,892	4.4%	69%
Pinnacle West	PNW	N	55.17	8.0%	61.00	14.6%	111	6,120	3,686	9,806	4.0%	60%
Pepco Holdings	POM	U	18.54	8.8%	21.00	19.1%	246	4,569	5,237	9,805	5.0%	67%
PPL Corp	PPL	N	30.49	9.7%	35.00	19.7%	666	20,295	20,513	40,813	4.9%	64%
Southern Co	SO	U	41.77	10.5%	48.00	18.9%	878	36,633	23,924	60,558	4.8%	73%
Teco Energy	TE	R	16.07	R	R	R	R	R	R	R	R	R
Unisource Energy	UNS	N	47.11	4.3%	48.00	1.3%	42	1,958	1,924	3,892	3.7%	63%
Edison International	EIX	N	46.81	10.2%	53.00	16.5%	327	15,930	10,939	25,169	2.9%	40%
Allete Inc*	ALE	NR	48.34	5.7%	NR	NR	40	1,914	937	2,852	3.9%	70%
Alliant Energy Corp*	LNT	NR	50.05	7.4%	NR	NR	111	5,545	5,045	10,590	3.8%	60%
Northeast Utilities*	NU	NR	41.34	9.0%	NR	NR	316	13,062	9,382	22,444	3.5%	57%
OGE Energy Corp*	OGE	NR	35.99	26.3%	NR	NR	199	7,162	3,068	10,228	2.3%	47%
Scana*	SCG	NR	46.51	13.0%	NR	NR	140	6,493	6,190	12,673	4.4%	60%
Wisconsin Energy*	WEC	NR	40.84	6.9%	NR	NR	231	9,414	5,007	14,420	3.5%	58%
Xcel Energy*	XEL	NR	27.86	8.9%	NR	NR	490	13,875	11,970	25,854	4.0%	59%
S&P 500 (Consensus)	SPX		1,672.72									
Average (ex AWK, BKH, CNP, ITC, NVE, OGE)						10.0%	345	15,471	15,161	27,852	4.1%	64%
Utes Avg CS Universe (Large Cap)						18.4%	519	26,130	22,232	50,366	4.4%	67%
Utes Avg CS Universe (ex AWK, BKH, CNP, ITC, NVE)						18.0%	401	16,745	14,846	33,562	4.5%	65%
Utes Avg CS Universe (Small & Mid Caps ex AWK, BKH, CNP, ITC, NVE)						16.3%	195	7,789	6,215	13,966	4.0%	65%

		CS Estimated EPS				Price-to-Earnings						
Companies	Ticker	2012A	2013E	2014E	2015E	2012A	2013E	2014E	2015E	PE Relative Group 2013	PE Relative Group 2014	'12/'16 EPS Growth Rate
American Electric Power	AEP	3.09	3.18	3.26	3.35	14.2x	13.8x	13.4x	13.1x	90%	91%	2.6%
American Water Works Co	AWK	2.11	2.22	2.37	2.55	19.3x	18.4x	17.2x	16.0x	117%	116%	7.1%
Black Hills Corp	BKH	2.03	2.37	2.54	2.68	22.6x	20.8x	19.4x	18.4x	133%	132%	5.8%
CMS Energy Corp	CMS	1.55	1.65	1.76	1.87	17.0x	16.0x	15.0x	14.1x	102%	102%	6.2%
Dominion Resources	D	3.05	3.34	3.53	3.75	20.5x	18.7x	17.7x	16.6x	119%	120%	5.6%
DTE Energy	DTE	3.94	4.05	4.31	4.67	16.9x	16.4x	15.4x	14.2x	105%	105%	7.3%
Duke Energy	DUK	4.32	4.31	4.60	4.77	15.6x	15.6x	14.6x	14.1x	100%	99%	3.1%
Consolidated Edison	ED	3.73	3.82	3.84	3.97	14.9x	14.6x	14.5x	14.1x	93%	95%	2.6%
ITC Holdings Corp	ITC	4.14	4.93	5.65	6.43	22.5x	18.9x	16.5x	14.5x	120%	112%	13.9%
NV Energy Inc	NVE	1.33	1.33	1.32	1.38	17.7x	17.7x	17.8x	17.1x	112%	121%	1.6%
PG&E Corp	PCG	3.22	2.65	3.10	3.26	13.0x	15.8x	13.5x	12.8x	101%	91%	2.7%
Pinnacle West	PNW	3.50	3.65	3.73	3.82	15.7x	15.1x	14.8x	14.5x	96%	100%	2.0%
Pepco Holdings	POM	1.21	1.11	1.22	1.35	15.3x	16.7x	15.2x	13.7x	107%	105%	5.1%
PPL Corp	PPL	2.42	2.33	2.14	2.17	12.6x	13.2x	14.3x	14.0x	84%	97%	0.3%
Southern Co	SO	2.65	2.76	2.83	2.97	15.7x	15.1x	14.7x	14.0x	97%	100%	4.3%
Unisource Energy	UNS	2.20	2.65	3.38	3.14	21.4x	17.8x	14.0x	15.0x	113%	95%	4.8%
Edison International	EIX	4.55	3.35	3.52	3.50	10.3x	13.9x	13.3x	13.3x	89%	90%	3.2%
Allete Inc*	ALE	2.60	2.71	2.92	3.30	18.7x	17.8x	16.5x	14.7x	114%	112%	6.6%
Alliant Energy Corp*	LNT	3.05	3.14	3.31	3.46	16.4x	15.9x	15.1x	14.4x	102%	103%	4.2%
Northeast Utilities*	NU	2.28	2.57	2.72	2.89	18.2x	16.1x	15.2x	14.3x	103%	103%	6.1%
OGE Energy Corp*	OGE	0.90	1.77	1.97	2.11	39.9x	20.3x	18.2x	17.0x	129%	125%	6.0%
Scana*	SCG	3.19	3.37	3.50	3.66	14.6x	13.8x	13.3x	12.7x	89%	90%	6.0%
Wisconsin Energy*	WEC	2.35	2.45	2.56	2.69	17.4x	16.7x	15.9x	15.2x	106%	106%	4.0%
Xcel Energy*	XEL	1.82	1.90	1.99	2.08	15.3x	14.6x	14.0x	13.4x	94%	95%	3.8%
S&P 500 (Consensus)	SPX	103.80	109.90	118.60	126.87	16.2x	15.5x	14.3x	13.1x	90%	97%	
Average (ex AWK, BKH, CNP, ITC, NVE, OGE)						16.0x	15.7x	14.9x	14.1x			
Utes Avg CS Universe (Large Cap)						15.9x	15.2x	14.7x	14.1x			
Utes Avg CS Universe (ex AWK, BKH, CNP, ITC, NVE)						15.6x	15.6x	14.8x	14.3x			
Utes Avg CS Universe (Small & Mid Caps ex AWK, BKH, CNP, ITC, NVE)						16.1x	16.0x	14.6x	14.1x			

		CS Estimated EBITDA			Adj EV-to-EBITDA							
Companies	Ticker	2013E	2014E	2015E	2013E	2014E	2015E	FFO/D&M 2013E	Net Debt/ Cap 2013E	EV/Rate Base 2013E	P/BV 2013E	Price vs. 50/200 Day Avg
American Electric Power	AEP	4,893	5,080	5,143	8.2x	8.2x	8.5x	20%	54%	1.2x	1.7x	100.7% / 94.9%
American Water Works Co	AWK	1,250	1,417	1,488	9.7x	9.5x	9.1x	17%	55%	NM	1.5x	90.0% / 98.8%
Black Hills Corp	BKH	410	435	457	8.9x	8.7x	8.6x	27%	53%	1.4x	1.7x	99.0% / 102.4%
CMS Energy Corp	CMS	1,643	1,794	1,835	8.9x	8.8x	8.7x	17%	60%	1.2x	2.1x	99.5% / 95.5%
Centerpoint Energy	CNP	R	R	R	NM	NM	NM	R	R	NM	R	R
Dominion Resources	D	5,134	5,580	5,980	11.8x	11.1x	10.0x	19%	65%	2.0x	3.1x	104.9% / 106.4%
DTE Energy	DTE	2,471	2,708	2,754	8.0x	7.5x	7.5x	23%	51%	1.2x	1.5x	98.4% / 97.2%
Duke Energy	DUK	8,901	8,879	9,156	10.9x	10.3x	10.1x	15%	51%	1.6x	1.1x	100.1% / 96.5%
Consolidated Edison	ED	3,333	3,412	3,645	8.4x	8.2x	8.1x	18%	43%	1.2x	1.3x	98.3% / 94.6%
ITC Holdings Corp	ITC	685	797	891	12.3x	11.1x	10.2x	12%	69%	NM	3.0x	103.8% / 103.7%
NV Energy Inc	NVE	1,170	1,189	1,215	8.7x	8.4x	8.3x	16%	56%	1.3x	1.5x	99.8% / 105.4%
PG&E Corp	PCG	4,507	5,226	5,590	7.2x	6.8x	6.7x	22%	46%	1.3x	1.2x	98.0% / 93.5%
Pinnacle West	PNW	1,309	1,369	1,453	7.5x	7.6x	6.0x	27%	46%	0.9x	1.4x	100.4% / 96.6%
Pepco Holdings	POM	1,546	1,324	1,447	6.3x	7.8x	7.5x	8%	55%	1.4x	1.1x	97.4% / 90.8%
PPL Corp	PPL	4,305	4,301	4,482	9.5x	9.8x	8.8x	14%	63%	1.7x	1.7x	99.1% / 98.8%
Southern Co	SO	6,400	6,769	7,166	9.5x	9.4x	9.1x	19%	54%	1.6x	1.9x	99.3% / 93.5%
Teco Energy	TE	R	R	R	NM	NM	NM	R	R	R	R	R
Unisource Energy	UNS	470	525	524	8.3x	7.9x	8.5x	17%	63%	1.6x	1.5x	100.5% / 98.3%
Edison International	EIX	3,925	4,252	4,405	6.7x	6.5x	6.5x	27%	43%	1.2x	1.6x	100.2% / 95.9%
Allete Inc*	ALE	265	303	330	10.8x	9.4x	8.6x	20%	44%	NM	1.5x	100.0% / 97.6%
Alliant Energy Corp*	LNT	925	1,006	1,060	11.4x	10.6x	10.4x	19%	51%	NM	1.7x	99.3% / 93.6%
Northeast Utilities*	NU	2,183	2,593	2,374	10.3x	10.0x	9.9x	16%	49%	NM	1.2x	99.4% / 95.6%
OGE Energy Corp*	OGE	1,059	1,131	1,194	9.6x	8.9x	8.5x	21%	52%	NM	1.9x	99.5% / 102.1%
Scana*	SCG	1,331	1,418	1,501	9.5x	8.9x	8.2x	14%	59%	NM	1.5x	96.3% / 92.4%
Wisconsin Energy*	WEC	1,438	1,470	1,519	10.0x	9.7x	9.5x	13%	56%	NM	2.3x	99.0% / 97.0%
Xcel Energy*	XEL	2,911	3,110	3,270	8.9x	8.6x	8.0x	17%	55%	NM	1.5x	99.1% / 93.5%
Average (ex AWK, BKH, CNP, ITC, NVE, OGE)					9.0x	8.8x	8.7x	18%	54%		1.4x	99.5% / 95.3%
Utes Avg CS Universe (Large Cap)					9.3x	9.1x	9.0x	18%	55%		1.7x	100.1% / 96.8%
Utes Avg CS Universe (ex AWK, BKH, CNP, ITC, NVE)					8.9x	8.5x	8.4x	19%	55%		1.5x	99.8% / 95.3%
Utes Avg CS Universe (Small & Mid Caps ex AWK, BKH, CNP, ITC, NVE)					7.6x	7.7x	7.0x	20%	55%		1.6x	99.7% / 93.4%

Source: Factset, CS estimates, company data   *Factset - consensus estimates

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Competitive Power

(Dollars in millions, except per share amounts)

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Companies	Ticker	Rating	Price [illegible]	Target Price	Total Return Potential	Shares 2013E	Market Cap	Net Debt 2013E	Enterprise Value	Dividend Yield 2013E	Dividend Payout 2013E
Dominion Resources	D	O	62.42	65.00	7.7%	579	36,126	23,401	59,527	3.6%	67.5%
Entergy Corp	ETR	N	69.63	65.00	7.4%	179	11,364	13,104	24,468	5.2%	65.6%
Exelon Corp	EXC	N	30.31	28.00	-3.1%	859	26,033	20,133	46,165	4.6%	55.9%
FirstEnergy Corp	FE	N	37.09	37.00	5.7%	418	15,516	19,312	34,828	5.9%	73.6%
NextEra Energy	NEE	O	80.33	91.00	16.5%	425	34,120	26,932	61,053	3.2%	51.5%
Public Svc. Enterprise Grp	PEG	N	33.55	31.00	-3.3%	507	17,018	8,676	25,693	4.3%	59.0%
PPL Corp	PPL	N	30.49	35.00	19.7%	666	20,299	20,513	40,812	4.9%	64.3%
Sempra Energy*	SRE	NR	80.72	NR	NR	244	21,125	12,249	33,375	2.9%	57.9%
Ameren Corp*	AEE	NR	35.44	NR	NR	243	9,598	6,693	15,291	4.5%	76.3%
El Paso Electric*	EE	NR	33.11	NR	NR	40	1,328	990	2,326	3.2%	44.1%
PNM Resources*	PNM	NR	22.49	NR	NR	80	1,786	1,984	3,760	2.9%	47.9%
S&P 500 (Consensus)	SPX		1,692.77								
Utes Average					7.2%					4.1%	62.3%
Average (ex PPL)					5.2%					4.0%	59.8%

		CS Estimated EPS				Price-to-Earnings				PE Relative	PE Relative
Companies	Ticker	2012A	2013E	2014E	2015E	2012A	2013E	2014E	2015E	Group 2013	Group 2014
Dominion Resources	D	3.05	3.34	3.53	3.75	20.5x	18.7x	17.7x	16.6x	124%	120%
Entergy Corp	ETR	6.23	5.06	5.20	5.12	10.2x	12.6x	12.2x	12.3x	83%	83%
Exelon Corp	EXC	3.43	2.47	2.33	2.41	8.8x	12.3x	13.0x	12.6x	81%	88%
FirstEnergy Corp	FE	3.34	2.99	3.06	3.48	11.1x	12.4x	12.1x	10.7x	82%	82%
NextEra Energy	NEE	4.58	5.01	5.26	5.67	17.5x	16.0x	15.3x	14.2x	106%	104%
Public Svc. Enterprise Grp	PEG	2.44	2.48	2.38	2.26	13.8x	13.5x	14.1x	14.9x	90%	96%
PPL Corp	PPL	2.42	2.30	2.14	2.17	12.6x	13.2x	14.3x	14.0x	88%	97%
Sempra Energy*	SRE	4.35	4.35	4.50	4.88	19.8x	19.8x	19.3x	17.8x	132%	131%
Ameren Corp*	AEE	2.42	2.10	2.28	2.52	14.6x	16.9x	15.6x	14.1x	112%	106%
El Paso Electric*	EE	2.26	2.38	2.48	2.38	14.7x	13.9x	13.4x	13.9x	92%	91%
PNM Resources*	PNM	1.31	1.37	1.47	1.65	17.2x	16.4x	15.3x	13.7x	109%	104%
S&P 500 (Consensus)	SPX	103.80	109.36	118.60	129.67	16.3x	15.5x	14.3x	13.1x	103%	97%
Utes Average		3.26	3.08	3.15	3.30	14.6x	15.1x	14.7x	14.1x		
Average (ex PPL)		3.34	3.16	3.25	3.42	14.8x	15.2x	14.8x	14.1x		

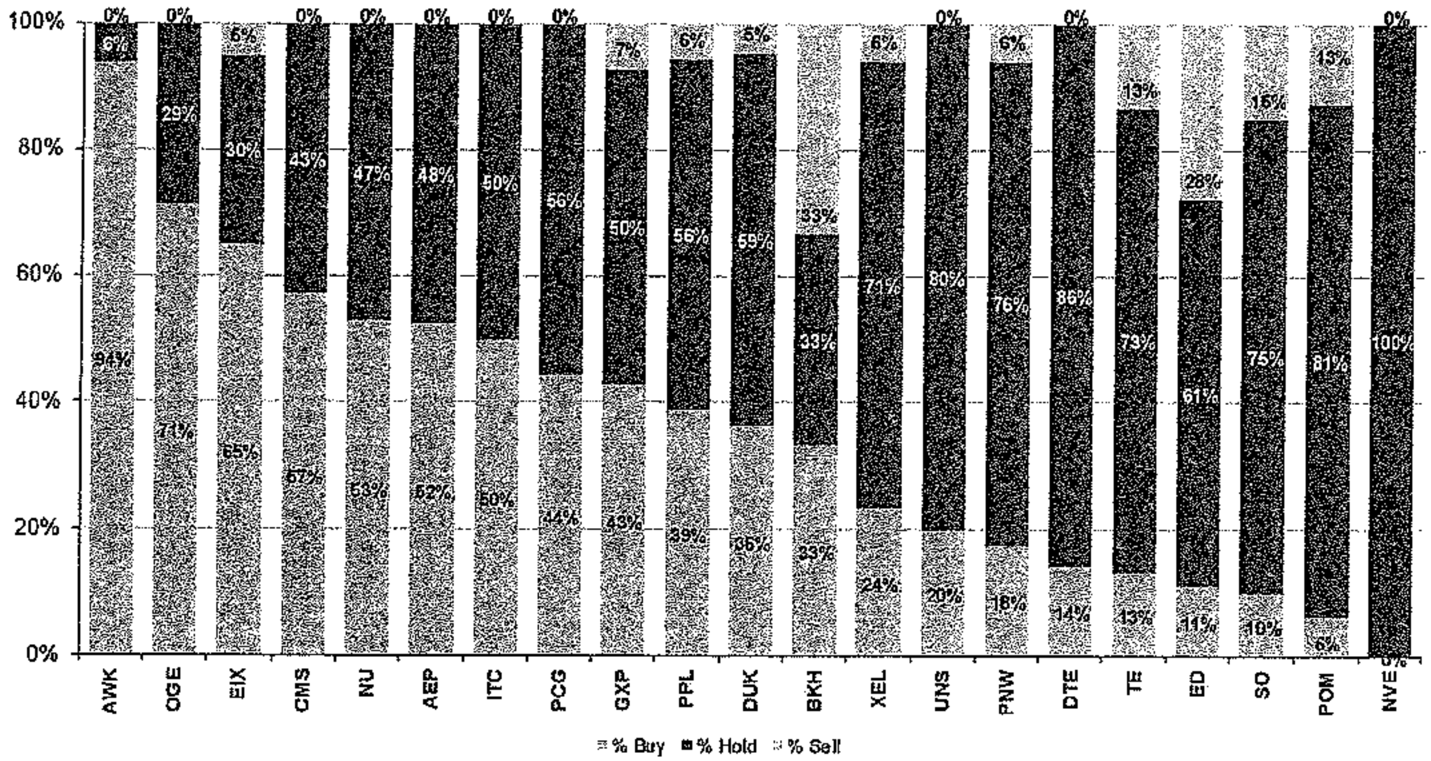
		CS Estimated EBITDA				Adj EV-to-EBITDA				Relative	Relative
Companies	Ticker	2012A	2013E	2014E	2015E	2012A	2013E	2014E	2015E	Group 2013	Group 2014
Dominion Resources	D	4,828	5,134	5,560	5,980	12.3x	11.6x	11.1x	10.6x	131%	126%
Entergy Corp	ETR	3,028	3,233	3,296	3,342	8.1x	7.6x	7.6x	7.6x	86%	86%
Exelon Corp	EXC	6,604	6,138	6,014	6,282	7.0x	7.5x	7.8x	7.7x	85%	89%
FirstEnergy Corp	FE	4,357	4,155	4,153	4,492	8.0x	8.4x	8.4x	7.8x	95%	95%
NextEra Energy	NEE	5,105	6,276	6,715	7,385	12.0x	9.7x	9.3x	8.5x	110%	105%
Public Svc. Enterprise Grp	PEG	3,218	3,414	3,430	3,406	8.0x	7.5x	7.7x	7.8x	85%	87%
PPL Corp	PPL	4,082	4,305	4,301	4,492	10.0x	9.5x	9.6x	9.0x	107%	111%
Sempra Energy*	SRE	2,649	3,203	3,370	3,665	12.6x	10.4x	10.3x	9.7x	118%	117%
Ameren Corp*	AEE	2,103	1,929	2,007	2,139	7.3x	7.9x	7.9x	7.6x	90%	89%
El Paso Electric*	EE	247	269	284	301	9.4x	8.6x	8.9x	8.7x	98%	101%
PNM Resources*	PNM	438	454	462	519	8.6x	8.3x	8.3x	7.9x	94%	94%
Utes Average		3,393	3,501	3,609	3,818	9.4x	8.8x	8.8x	8.5x		
Average (ex PPL)		3,259	3,420	3,533	3,751	9.3x	8.6x	8.7x	8.4x		

		Total Return		Power Hedge			Moody's	Debt/EBITDA	FFO/Debt	Net Debt/	Price vs.
Companies	Ticker	YTD	LTM	2013E	2014E	2015E	Debt Rating	2013E	2013E	Cap 2013E	50/200 Day Avg
Dominion Resources	D	25.0%	22.7%	99%	80%	58%	Baa2	4.9x	19%	65%	105% / 106%
Entergy Corp	ETR	-5.0%	-3.2%	83%	77%	39%	Baa3	4.4x	21%	57%	99% / 95%
Exelon Corp	EXC	-25.1%	-9.6%	98%	80%	43%	Baa2	3.2x	25%	48%	100% / 93%
FirstEnergy Corp	FE	-47.6%	-11.3%	96%	50%	20%	Baa3	4.4x	17%	60%	99% / 93%
NextEra Energy	NEE	39.5%	19.1%	98%	95%	89%	Baa1	5.4x	19%	61%	98% / 100%
Public Svc. Enterprise Grp	PEG	9.2%	9.9%	73%	58%	33%	Ba1	2.7x	27%	43%	102% / 100%
PPL Corp	PPL	12.3%	10.2%	99%	77%	0%	Baa3	5.2x	14%	63%	99% / 99%
Sempra Energy*	SRE	65.6%	37.2%	-	-	-	Baa1	4.0x	17%	54%	102% / 105%
Ameren Corp*	AEE	15.4%	13.0%	-	-	-	Baa3	3.8x	17%	50%	104% / 102%
El Paso Electric*	EE	0.9%	-1.2%	-	-	-	Baa2	4.0x	17%	52%	96% / 93%
PNM Resources*	PNM	29.7%	9.7%	-	-	-	Ba1	2.5x	24%	49%	100% / 99%
Utes Average		14.5%	6.6%					4.0x	20%	55%	
Average (ex PPL)		14.7%	8.6%					3.9x	20%	54%	

Source: Factset, CS estimates, company data

*Factset - consensus estimates

Distribution of Street Ratings – Regulateds



Avg Rec: 1=Buy, 2=Hold, 3=Sell / Number of Recs

	AWK	OGE	EIX	CMS	NU	AEP	ITC	PCG	GXP	PPL	DUK	BKH	XEL	UNS	PNW	DTE	TE	ED	SO	POM	NVE
Avg Rec	1.06	1.29	1.40	1.43	1.47	1.48	1.50	1.56	1.64	1.67	1.68	2.00	1.82	1.80	1.88	1.86	2.00	2.17	2.05	2.06	2.00
# Recs	16	7	20	14	17	21	6	16	14	18	22	6	17	5	17	14	15	18	20	16	13

Source: Factset

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Companies Mentioned *(Price as of 25-Sep-2013)*

AES Corporation (AES.N, $13.58)
Ameren (AEE.N, $35.55)
American Electric Power Co. Inc. (AEP.N, $43.91)
American Water Works (AWK.N, $40.76)
Aqua America (WTR.N, $24.59)
Black Hills Corp (BKH.N, $49.5)
CMS Energy (CMS.N, $26.48)
Calpine (CPN.N, $19.83)
CenterPoint Energy Inc (CNP.N, $24.08)
Cleco (CNL.N, $45.54)
Con Edison (ED.N, $55.92)
Covanta Holding (CVA.N, $21.43)
DTE Energy (DTE.N, $66.81)
Dominion Resources (D.N, $62.86)
Duke Energy (DUK.N, $67.53)
Edison International (EIX.N, $46.78)
Entergy Corporation (ETR.N, $63.7)
Exelon Corporation (EXC.N, $30.41)
FirstEnergy (FE.N, $37.37)
GenOn Energy, Inc. (GEN.N, $2.87)
Great Plains Inc (GXP.N, $22.55)
ITC Holdings Corp (ITC.N, $93.17)
Integrys Eng (TEG.N, $55.83)
NRG Energy (NRG.N, $28.16)
NV Energy Inc (NVE.N, $23.58)
NextEra Energy Inc. (NEE.N, $80.79)
NiSource Inc. (NI.N, $30.8)
Northeast Utilities (NU.N, $41.48)
OGE Energy (OGE.N, $36.18)
Ormat Tech (ORA.N, $26.76)
PG&E Corporation (PCG.N, $41.96)
PNM Resources (PNM.N, $22.59)
PPL Corporation (PPL.N, $30.53)
Pepco Holdings Inc. (POM.N, $18.62)
Pinnacle West Capital Corp. (PNW.N, $55.46)
Public Svc Ent (PEG.N, $33.59)
SCANA (SCG.N, $46.72)
Sempra Ener (SRE.N, $86.86)
Southern Company (SO.N, $41.81)
TECO Energy (TE.N, $17.0)
Unisource Energy Corp (UNS.N, $47.26)
Westar Energy (WR.N, $31.12)
Wisconsin Energy (WEC.N, $41.02)
Xcel Energy (XEL.N, $27.94)

Disclosure Appendix

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Restricted	3%	

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From: Takemori, Shimbi (VZDP 191) [shimbi.takemori@credit-suisse.com]
Sent: 10/1/2013 8:31:10 PM
To: amy.brodrick@cpuc.ca.gov
Subject: Updated attendees from Credit Suisse to meet with Marcelo Poirier and Rachel Peterson at 11am tomorrow Oct. 2
Attachments: image002.png; image003.jpg; image001.png; California Trip Questions v4.pdf.pdf.pdf.pdf.pdf

Hi Amy,

Here is the updated list:

Attendee	Corporation	Notes
Dan Eggers	Credit Suisse	Host
Branden Heiken	Credit Suisse	
Adam Ward	Capital Research	Investor
Stephen Huang	Carlson Capital LP	Investor
Jeremiah Casey	Eaton Vance	Investor
Kevin Walenta	Fidelity Management & Research Co	Investor
John Kohli	Franklin Advisors	Investor
Blair Schmicker	Franklin Advisors	Investor
Jeff Chrzanowski	George Weiss Associates Inc.	Investor
Tom O'Neill	Green Arrow	Investor
Claud Davis	MFS Investment Management	Investor
Hasan Goncu	Morgan Stanley Investment Mgmt	Investor
Michael Levy	UBS Global	Investor

I have also included the investor packet containing CA regulatory topics of interest in the back.

Thank you,

Shimbi Takemori

Eqr US Assistant - NY

+1 212 325 9961 (*105 9961)

From: Davis, Matthew S. (VZDS 11)
Sent: Wednesday, September 11, 2013 11:31 AM
To: Brodrick, Amy
Cc: Takemori, Shimbi (VZDP 191)
Subject: RE: MeetingConfirmation

Good Morning Amy,

I wanted to follow up on our earlier email communication about Dan Egger's meeting with Comr Florio's Senior Legal Advisor (Marcelo Poirier) and Senior Energy Advisor (Rachel Peterson) on October 2, 2013 from 11.00-11.30 AM (PDT). Dan will be bringing 11 investors along with him for a total of 12 people, is there a room location that you have that I would be able to include on an itinerary. Additionally, are there any special security clearance requirements that we should coordinate ahead of time? Once again thank you for your help in organizing this meeting.

One note is that I will be out of the office starting September 19th through October 7th for my wedding and honeymoon so your point of contact regarding any changes or questions during that time should be directed at Shimbi Takemori who is also cc'd on this email.

Thank you,

Matt

Attendee	Corporation	Notes
Dan Eggers	Credit Suisse	Host
Kevin Walenta	Fidelity Management & Research Co	Investor
Stephen Huang	Carlson Capital LP	Investor
Andre Meade	Capital World	Investor
Adam Ward	Capital Research	Investor
Jeff Chrzanowski	George Weiss Associates Inc.	Investor
Jeremiah Casey	Eaton Vance	Investor
Larry Alberts	Columbia Mgmt	Investor
Chris Shelton	Millennium Mgmt	Investor
Gregg Reiss	Millennium Mgmt	Investor
Tom O'Neill	Green Arrow	Investor
Claud Davis	MFS Investment Management	Investor

From: Brodrick, Amy [mailto:amy.brodrick@cpuc.ca.gov]
Sent: Monday, August 19, 2013 4:38 PM
To: Davis, Matthew
Subject: MeetingConfirmation

Dan Eggers - General Discussion

State of California

Memorandum

Date: August 19, 2013

To: Matthew Davis

From: Amy Brodrick

Office of Commr. Michel Florio

Public Utilities Commission—San Francisco

Re: **Meeting Request Dated: August 7, 2013– General Discussions**

This will confirm that your meeting request for the above date has been set for

(October 2, 2013), (11:30a.m.), (Room 5209) with **(Marcelo Poirier, Rachel Peterson).**

Please check in at the Security Desk in the main lobby to obtain a security badge before proceeding to your meeting. If you did not do so in your original Meeting Request Form,

please submit a complete list of attendees prior to your meeting date.

If you need to cancel or change this meeting time for any reason, please let us know at your earliest convenience. Thank you for your request, and we look forward to seeing you at the PUC.

Message

From:	Susan Davies [SDavies@isigrp.com]
Sent:	6/18/2013 5:42:11 PM
To:	'Banks, Juliane' [juliane.banks@cpuc.ca.gov]
Subject:	RE: Meeting with Commissioner Ferron Wed 6/19 at 11am in San Francisco

Hi Juliane,

Thanks for asking and I can also give you some history as well.

Greg Gordon has hosted meetings before with other California Commissioners including President Peevey and Carol Brown, both in person and via video phone from our offices here in NY.

He has been covering the CPUC's policy decisions for 20 years, first as a regulatory analyst at Regulatory Research Associates and since at several other institutions. ISI Group is a research only organization, although the members of the group that is attending include both equity and credit investors in CA's utility infrastructure.

Greg realizes there are several pending cases in front of the CPUC, including PG&E's electric rate case, the Pipeline case, the SCE case regarding the San Onofre plant, etc. and that your office cannot/will not "predict the future" on cases that have not yet been decided.

The issues/topics we will want to cover will focus on is Commissioner Ferron's philosophical position, given his record as a Commissioner at the CPUC, as it pertains to different matters that may be before the Commission now or in the future, NOT specific questions as to how he might rule "up or down" on any pending or future issues before the Commission. Some attendees might want to pose hypothetical questions to your team on how they think the Commissioner would respond to different economic or regulatory scenarios, given his regulatory philosophy and decision making framework.

These issues might include:

Historic decisions and protocol with regard to the prudence and usefulness of assets and the precedence of those decisions.

The current ROE/Cap structure framework and its durability.

The need/desire for continued infrastructure investment in power and gas and how that gets paid for under different economic forecasts.

Rate design issues and how they are resolved as it pertains to solar tariffs and other rates.

The legal framework regarding the CPUC's ability and flexibility to implement fines and penalties.

The group looks forward to seeing you on Wednesday.

Susan Davies Exec Asst to Greg Gordon

ISI Group LLC 666 Fifth Ave NYC 10103

212-653-8978

From: Banks, Juliane [mailto:juliane.banks@cpuc.ca.gov]
Sent: Tuesday, June 18, 2013 1:23 PM
To: Susan Davies
Subject: RE: Meeting with Commissioner Ferron Wed 6/19 at 11am in San Francisco

Hi Susan,

Could you provide me with a list of topics that the attendees will want to discuss at tomorrow's meeting?

Thanks,

Juliane

From: Susan Davies [mailto:SDavies@isigrp.com]
Sent: Friday, June 14, 2013 1:04 PM
To: Banks, Juliane
Subject: RE: Meeting with Commissioner Ferron Wed 6/19 at 11am in San Francisco

Great Juliane. I am glad that will work.

Would you have the email the research should be sent to?

The group will not have a handout for the meeting.

Thanks for your help!

From: Banks, Juliane [mailto:juliane.banks@cpuc.ca.gov]
Sent: Friday, June 14, 2013 3:10 PM
To: Susan Davies
Subject: RE: Meeting with Commissioner Ferron Wed 6/19 at 11am in San Francisco

Hi Susan,

Thanks for the update. The room I reserved should be big enough to accommodate everyone. As a reminder, please make sure the attendees add Comr. Ferron to their research distribution list. Please also be sure to forward me an electronic copy of any potential handouts.

Thanks,

Juliane

From: Susan Davies [mailto:SDavies@isigrp.com]
Sent: Friday, June 14, 2013 8:56 AM
To: Banks, Juliane
Subject: Meeting with Commissioner Ferron Wed 6/19 at 11am in San Francisco

Hi Juliane,

Just getting in touch to let you know the attendees for the meeting this Wednesday at 11am with Commissioner Ferron.

I am in process of confirming the attendees for the trip out there. There may be a few less (but no more than this).

I am sorry the group became large, but I hope not too large.

Standing room is completely fine.

Thanks, Susan Davies

Susan Davies Exec Asst to Greg Gordon

ISI Group LLC 666 Fifth Ave NYC 10103

212-653-8978

List of Attendees

Greg Gordon	ISI Group
Jon Cohen	ISI Group
Marcus Cole	Zimmer Partners
Scott Senchak	Decade
Michael Goldenberg	Luminus
Stephen Huang	Carlson Capital
Tom O'Neill	Green Arrow
Adam Ward	Capital Group
Hema Gunasekaran	Nuveen
Benj Bahr	AllianceBernstein
Matt Fallon	Talon Capital
George Ross	First Eagle
Leslie Rich	JP Morgan Asset Mgmt

Message

From:	Surina.Diddi@ubs.com [Surina.Diddi@ubs.com]
Sent:	1/10/2014 5:09:59 PM
To:	juliane.banks@cpuc.ca.gov
CC:	Julien.Dumoulin-Smith@ubs.com
Subject:	RE: invitation to present at UBS panel at NARUC
Attachments:	disclaim.txt

Hi Juliane,

Thanks for your email. Please see my responses below in green. Don't hesitate to voice any other questions or concerns.

Hope Commissioner Ferron can join us.

Thanks,

Surina

From: Banks, Juliane [mailto:juliane.banks@cpuc.ca.gov]
Sent: Wednesday, January 08, 2014 4:37 PM
To: Diddi, Surina
Cc: Morales, Cristina
Subject: FW: invitation to present at UBS panel at NARUC

Hi Surina,

Comr. Ferron asked that I follow up with you to get some additional information:

- Who are the other invited panel members?

  We have invited Commissioners from across the country to present. We are still firming up our schedule. Currently have Commissioners from 5 states committed... to provide some context, we held similar panels at the last NARUC meeting—and over 14 Commissioners from across the country spoke. I would be happy to provide more details there.

- Do you have an idea of who the investors are that the panel will be presenting to, as well as anyone else you expect to attend?

  They will be primarily utility investors as well as some folks from infrastructure funds/ generalist hedge funds.

- Can you give us an idea of what kind of questions you expect to be asked?

  We hope to foster a high-level discussion about Commissioner Ferron's outlook for energy policy in California. We will certainly be respectful to not ask about any issues open in front of the Commission. Some potential topics include: net metering, RPS standards, renewables at large—potential to disrupt the utility landscape, the aftermath of SONGS, etc. We would be happy to set ground rules about permissible potential topics and even send you a list of questions beforehand if needed.

- Do you have an agenda for this event?

  As mentioned we are still firming up our schedule, but as of now, we have Commissioners from 5 states committed. We will send this to you shortly.

Thank you for your assistance,

Juliane

Juliane Banks

Assistant to Commissioner Mark Ferron

California Public Utilities Commission

Direct: 415-703-2284 / Main: 415-703-2444 / Fax: 415-703-1903

bnk@cpuc.ca.gov

Begin forwarded message:

From: <Surina.Diddi@ubs.com>
Date: December 30, 2013 at 8:11:45 AM PST
To: <mark.ferron@cpuc.ca.gov>
Cc: <Julien.Dumoulin-Smith@ubs.com>, <cristina.morales@ubs.com>
Subject: invitation to present at UBS panel at NARUC

Dear Commissioner Ferron,

I work for UBS in the utilities investment research group in New York. We would like to invite you to present as part of a panel in front of a group of investors, as part of the **NARUC Conference**. Do let us know if you will be available on

Monday, February 10th in the afternoon. We are hosting several panels with Commissioners and their staff from across the country then. We would sincerely appreciate your participation.

We visited the CPUC in August along with a group of investors and meet with Commissioner Peterman and many of your colleagues then. We want to foster a high-level discussion about policy issues in California. My colleague, Julien Dumoulin-Smith, our Head Analyst, will be moderating the discussion.

Please let me know if you have any questions or concerns.

Thanks,

Surina

Surina Diddi

US Electric Utilities & IPPs Group
UBS Investment Research
1285 Ave. of the Americas, New York, NY 10019
Email: surina.diddi@ubs.com

(o) 1-212-713-1074

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From: Ferron, Mark
Sent: 4/12/2011 2:51:27 PM
To: Cherry, Brian K (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=BKC7)
Cc:
Bcc:
Subject: RE: Analyst Reports (BofA Merrill) - CA PUC Meetings and Quantifying San Bruno Risks

Hi Brian,

Thanks for sending me this. If you wouldn't mind, I would appreciate it if you would copy me on similar such analysts reports. I find the perspective of the analyst community quite useful.

Best regards

Mark

-----Original Message-----
From: Cherry, Brian K [mailto:BKC7@pge.com]
Sent: Tue 4/12/2011 12:04 PM
To: Ferron, Mark
Subject: FW: Analyst Reports (BofA Merrill) - CA PUC Meetings and Quantifying San Bruno Risks

Mark - FYI. I'd be happy to forward reports like this to you if you have an interest.

From: Togneri, Gabriel
Sent: Tuesday, April 12, 2011 10:18 AM
To: Officers of Pacific Gas and Electric; Officers of PG&E Corporation
Cc: Investor Relations (list); Lee, Wondy
Subject: Analyst Reports (BofA Merrill) - CA PUC Meetings and Quantifying San Bruno Risks

BofA Merrill lead analyst Steve Fleishman issued two reports this morning. One report focus on his meetings with the CPUC last week and implications for CA utilities generally. The other report is more specific to PCG and risks associated with the ongoing gas pipeline issues.

In the first report, "CA PUC Meetings Reasonable; Prefer EIX over PCG", Fleishman notes that the CPUC remains focused on the large infrastructure needs in the state and he believes that California continues to be a constructive regulatory environment, with the commissioners mentioning the need for healthy utilities to achieve the state's ambitious renewables targets. On specific issues, Fleishman reports:

Rate Base Investments - The commission continues to support strong rate base growth, particularly for safety, reliability, and renewables growth. Many of the commissioners also mentioned the need to consider affordability and this would indicate increased focus on renewable PPAs and targeting them to be more competitive.

Cost of Capital - Commissioners noted that CA ROEs are on the higher end and are likely to trend down, but not likely to industry averages recognizing the large investment needs in the state. All commissioners expressed support for a three-year cost of capital mechanism and Fleishman expects the current mechanism to stay in place.

Bonus D&A - Based on what he heard in his meetings, Fleishman believes this is moving in the right direction, with most commissioners supportive of having utilities spend the bonus D&A cash on additional investments that offsets the hit to rate base in latter years from increased deferred taxes.

CPUC Commissioner Update - The report states that Gov. Brown has asked President Peevey to stay at least through the end of 2011, and that it's possible one of the other commissioners will be named as president by the governor in 2012. It further speculates that under such a scenario President Peevey may step down from the commission allowing Gov. Brown to appoint a new commissioner in 2012. The report also notes that the CPUC is now operating under new Bagley-Keene rules that limit communications among Commissioners to public meetings, which Fleishman believes could result in some modest delays in coming to consensus on issues.

In the second report, "Quantifying San Bruno; Major Risk Priced In. Maintain Buy", Fleishman states that he believes San Bruno and its ramifications will likely get worse before it gets better. He has adjusted his estimates to reflect an additional $500 million of non-recoverable costs in addition to the $300 million previously assumed (a combination of direct costs and penalties). This has implications for the amount of equity issued to keep the capital structure at the authorized level, and dilutes his earnings estimates by about $0.10 on an annualized basis. In 2013, he also assumes that the equity ratio is lowered to 48% as part of the cost of capital review, consistent with other CA utilities, and that the ROE is lowered by 50 bps to 10.85%. Eventually, he believes PCG will see rate base growth to enhance the gas system, but the transition from shareholder-funded spend to "fix" the gas system to customer-funded spend to achieve best-in-class safety is uncertain.

As a result of the assumptions above, his EPS estimates for 2011-2014 are now $3.65/$3.80/$3.79/$3.88 compared to his previous estimates of $3.65/$3.89/$3.95/$4.05. He lowers his price target to $48, based on the industry average 12.5x 2013 EPS.

In trading today, we are currently at $43.80, down about 0.6%. This appears to be in the range that other regulated utility stocks are trading. The Dow Jones Utilities are down 0.35%.

Gabe

The contents of this email are provided solely for your information and are not intended as investment advice. We do not intend to endorse the opinions expressed in any externally prepared reports that may accompany this email and you should not rely on them for investment advice.

Gabe Togneri | VP Investor Relations | PG&E Corporation | 415.267.7100

From: Cherry, Brian K

Sent: 1/14/2014 5:26:04 PM

To: Brown, Carol A. (carol.brown@cpuc.ca.gov) (carol.brown@cpuc.ca.gov)

Cc:

Bcc:

Subject:

As long as ALJ Wong has the case (which Florio confirms), we are ok with what Mike wants to do on the assignment. Can you get it done ASAP please ?.

From: Cherry, Brian K
Sent: 11/4/2011 2:38:18 PM
To: Clanon, Paul (paul.clanon@cpuc.ca.gov) (paul.clanon@cpuc.ca.gov)
Cc:
Bcc:
Subject: FW: PCG Earnings release - MY VIEW

Paul - some interesting perspective from one of our major investors.

From: Togneri, Gabriel
Sent: Friday, November 04, 2011 11:07 AM
To: Earley Jr., Anthony; Harvey, Kent M; Johns, Christopher; Bottorff, Thomas E; Cherry, Brian K
Cc: Murphy, Margaret; Lam, Lisa
Subject: FW: PCG Earnings release - MY VIEW

All,

See note below from Larry Alberts of Columbia Management. Larry currently represents 4.5 million PCG shares and has been on the buy-side for a long time. He has an interesting calculation below suggesting that the PCG valuation is lagging the market by $5 billion since the San Bruno accident. Some of this cannot be attributed to San Bruno since Larry points out that all the CA UTEs have had some weakness associated with CA regulation, but a significant amount does represent a San Bruno "cost" to shareholders. I told Larry I would share this with you, including the Reg Rel folks who talk to the commission.

I would also like to share what else Larry said about our call yesterday. "I thought the conference call went very well. I know Tony is an outsider to most at PCG. But I have known him for years, and I think from all the possible CEO's in the industry who could have been considered, he was the best choice IMO for your issues. In actuality, I felt very positive about the prospects of the Company going forward. It is just a matter of getting from here to there."

Larry will not be at the EEI conference this year.

Gabe

Gabe Togneri | VP Investor Relations | PG&E Corporation | 415.267.7100

From: Alberts, Larry [mailto:larry.alberts@COLUMBIAMANAGEMENT.COM]
Sent: Friday, November 04, 2011 10:36 AM
To: Togneri, Gabriel
Subject: RE: PCG Earnings release - MY VIEW

Hi Gabe. Not much to say really. It is what it is.

I look at it perhaps in a different way than others. First, assuming San Bruno didn't happen, and PCG just performed with the group since, where would the stock be? About $53.50. I then take the differential between that number and where the stock trades. That differential is then translated into market cap, about $5.2B! Some of the premium companies have outperformed the space by an incremental 2%-5%, so that would add another $300MM-$900MM of "lost" market cap.

Now I would say the $5.2B+ covers anything related to San Bruno, changes in cost of capital/equity layer next year, etc., with plenty of cover. The question to PCG, is how do you get it back?

Personally, I would be taking such a calculation to the Commission, the Staff, the Gov, and say enough is enough. If the current PCG is going to be punished for past indiscretions, whether justified or not, the Commission and its staff should also be punished. Past and present, just like PCG.

But what are the repercussions for them? Tarnished reputations? All that I can say is WOW. How does that stack-up against the repercussions PCG has felt? And its investors? That is why I am of the opinion, though it will never happen, that Commissioners and their staff, should have stakes in the game, by being required to own shares in the companies they regulate.

Stock looks cheap, but institutional investors, and I don't mean hedge funds, have to believe it is not a value trap. Right now it looks like that for at least several years. PCG has to figure out of ways to convince institutional investors it is not. And the CA Commission, staff, Governor and legislature have to convince institutional investors it's still a good place to put money into. Right now one would have to say CA went from being one of the better regulatory environments, to average. AT BEST! Evidence has been provided by EIX and SRE being relative underperformers as well.

If all relevant parties in CA believe that there is what I would characterize as a "captive" audience of utility investors, I would emphatically say that is a mistaken view. Go back to the mid-1990's, you couldn't get anyone to buy utilities.

Larry

Lawrence S. Alberts | Vice President, Senior Equity Analyst | Fundamental Equity Corporate Research

Columbia Management | 10354 Ameriprise Financial Center | Minneapolis, MN, 55474

Office: 612.671.4107 | Fax: 612.317.3730 | Mobile: 612.747.9975

larry.alberts@columbiamanagement.com | **columbiamanagement.com**

From: Togneri, Gabriel [mailto:Gabriel.Togneri@pge-corp.com]
Sent: Thursday, November 03, 2011 6:17 AM
To: Alberts, Larry
Cc Redacted
Subject: PCG Earnings release

Larry,

We obviously have some difficult issues we'll be discussing on this quarterly call and I wanted to let you know that I will be available afterwards to talk one-on-one. Would you please let me know several times that would work for me to call you today. My assistant Kristin or I will get back to you with an approximate call time. Otherwise, I'll call you as soon as I can.

Thanks,

Gabe

Gabe Togneri | VP Investor Relations | PG&E Corporation | 415.267.7100

From: Cherry, Brian K
Sent: 1/17/2014 9:48:46 AM
To: Brown, Carol A. (carol.brown@cpuc.ca.gov)
Cc:
Bcc:
Subject: RE: GT& S Case Assigned

Please, please check. This is a major problem for us. Florio said he would agree to help Peterman if Wong got it.

From: Brown, Carol A. [mailto:carol.brown@cpuc.ca.gov]
Sent: Friday, January 17, 2014 9:48 AM
To: Cherry, Brian K
Subject: RE: GT& S Case Assigned

I can see if anything can be done

Sent from my Verizon Wireless 4G LTE smartphone

-------- Original message --------
From: "Cherry, Brian K"
Date:01/17/2014 11:38 AM (GMT-06:00)
To: "Brown, Carol A."
Subject: RE: GT& S Case Assigned

There is a huge world of difference between Long and Wong. I'm not sure we could get someone worse. This is a very important case that is now in jeopardy.

From: Brown, Carol A. [mailto:carol.brown@cpuc.ca.gov]
Sent: Friday, January 17, 2014 9:33 AM
To: Cherry, Brian K
Subject: RE: GT& S Case Assigned

I was told it would be Wong

We don't control judge assignments.

Think carefully before you bounce him -you could get some one worse.

Sent from my Verizon Wireless 4G LTE smartphone

-------- Original message --------
From: "Cherry, Brian K"
Date:01/17/2014 11:19 AM (GMT-06:00)
To: "Brown, Carol A."
Subject: RE: GT& S Case Assigned

We will bounce him and I don't want to do that.

-----Original Message-----
From: Cherry, Brian K
Sent: Friday, January 17, 2014 9:17 AM
To: Brown, Carol A. (carol.brown@cpuc.ca.gov)
Subject: FW: GT& S Case Assigned

Is this right ? Judge Long ? What happened to Wong ?

> On Jan 17, 2014, at 8:42 AM, Redacted wrote:
>
> The GTS case assignment appeared on the daily calendar - assigned to ALJ Long and Commissioner Peterman. I will issue a note to our team.
>
> Redacted
>
>
Redacted Office
Mobile

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PG&E is committed to protecting our customers' privacy.
To learn more, please visit http://www.pge.com/about/company/privacy/customer/

From: Cherry, Brian K
Sent: 1/17/2014 9:17:13 AM
To: Brown, Carol A. (carol.brown@cpuc.ca.gov) (carol.brown@cpuc.ca.gov)
Cc:
Bcc:
Subject: FW: GT& S Case Assigned

Is this right ? Judge Long ? What happened to Wong ?

> On Jan 17, 2014, at 8:42 AM, Redacted wrote:
>
> The GTS case assignment appeared on the daily calendar - assigned to ALJ Long and Commissioner Peterman. I will issue a note to our team.

>
> Redacted
>
>
>
>

From:	Stephen Byrd <stephen.byrd@morganstanley.com>
Sent:	Thursday, October 4, 2012 2:11 AM
To:	mark.ferron@cpuc.ca.gov
Subject:	Regulated Utilities: California Visit Takeaways

Morgan Stanley

OCTOBER 04, 2012 GMT

Regulated Utilities

California Visit Takeaways

Download the complete report (12 pgs)

The key takeaway from our meeting with all Commissioner offices at the CPUC is that regulation will remain balanced. We expect ROEs to remain above-average with supportive rate case resolution this quarter. We are also upgrading EIX to OW, but maintaining ratings on SRE (OW) and PCG (EW).

ROE premium to continue, but not likely to be large. From our meetings in California, there was recognition that premium returns were needed to incentivize investment and accomplish energy goals. While the magnitude was not noted, we expect it to be modest. We now utilize a 10.5% return for all three CA utilities as we believe it supports CPUC efforts. We also believe a 52% equity ratio is likely for SRE and PCG.

Supportive rate case decisions coming soon. There was frustration at the CPUC over delays with pending rate cases at EIX and SRE. However, decisions appear likely in the coming months. There was general support for healthy utilities that would be able to carry out state policy in a reliable and safe manner. This would likely lead to utilities earning allowed ROEs going forward.

San Bruno resolution getting close, but San Onofre just starting. A settlement relating to the San Bruno explosion is progressing. An agreement may not include all parties, which the CPUC noted some comfort with. We believe our $500mn fine estimate remains appropriate. Conversely, a San Onofre nuclear plant investigation is likely, but the CPUC appears to be reserving judgment on the cause/recovery. As a result, we do not expect a near-term EPS hit to EIX/SRE.

Supportive CPUC benefits all CA utilities. However, we are upgrading EIX given attractive valuation and more confidence in management walking away from its merchant power business. For SRE, we believe it is in great position through year-end with CA regulatory items and for 2013 with LNG export approvals. For PCG we appreciate the upcoming San Bruno settlement, but believe rate case uncertainty and considerable equity needs (~$1bn per year) limit upside.

Download the complete report (12 pgs)

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Regulated Utilities

Ask the Author a Question

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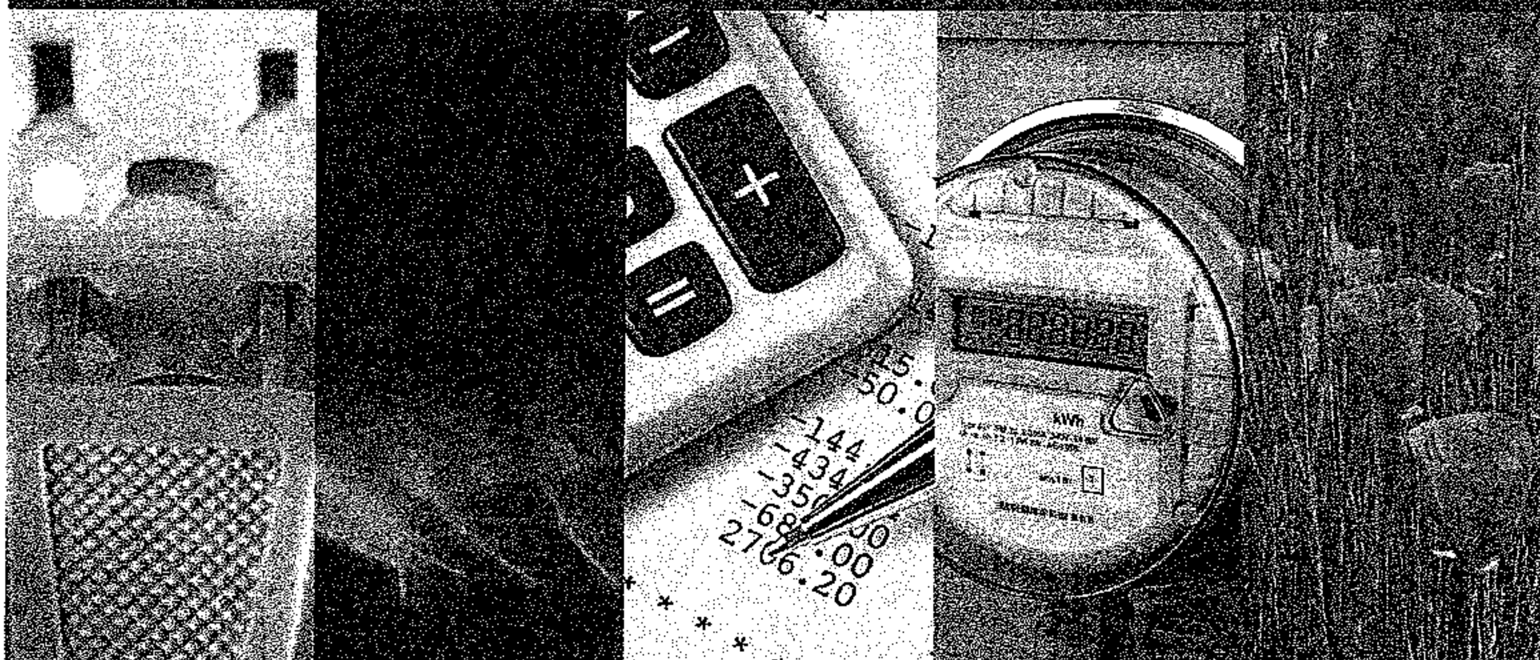
EXHIBIT 2

California Public Utilities Commission

Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases



May 2011

III. Electric Utility Revenue Requirements

Utilities file detailed descriptions of the costs of providing service (commonly referred to as revenue requirement to be collected from customers) in various proceedings and request the Commission to approve their proposed revenue requirement. The CPUC strives to balance electric utility customers' needs for safe, reliable, and environmentally responsible service and the financial health of the utility, while achieving the lowest possible rates. Since energy services are essential, the CPUC ensures that access is universal and affordable. The bulk of the utility's revenue requirements is requested in General Rate Cases (GRCs) and the Energy Resource Recovery Account (ERRA) proceedings. GRCs address a utility's request for maintaining and enhancing their generation and distribution infrastructure. ERRA costs are primarily fuel and purchased power costs which carry no mark-up or rate of return for the utility. In addition to the GRCs and ERRA proceedings, some costs are requested by the utilities in specific proceedings related to program areas such as energy efficiency, renewable portfolio standard (RPS), solar initiative, distributed generation and demand response.

As part of energy restructuring, the California Independent System Operator (CAISO) was created and given operational control over the utilities' high voltage lines on January 1, 1998. With that, the authority for determining transmission revenue requirements was transferred to the Federal Energy Regulatory Commission (FERC). However, the CPUC, through its Constitutional authority, represents the ratepayers of California at FERC in Transmission Owner (TO) Rate Cases. The transmission revenue requirements authorized by FERC involve the same major revenue requirement components (O&M, depreciation and return on rate base) as seen in general rate cases at the CPUC, including Return on Equity (ROE), Capital Additions, Operations and Maintenance Expense (O&M), Administrative and General Expense (A&G), Depreciation, Income Tax and Rate Base calculation.

In recent years, transmission-related revenue requirement and rate increases have largely been driven by capital additions and O&M.

All of the approved costs are recovered through three main types of rate charges—generation, distribution and transmission -- with some other charges such as the Public Purpose Charge (PPP), power and bond charges payable to the Department of Water resources (DWR) shown on customer bills as separate line items. The grouping of rates into generation, distribution and transmission is primarily based on the costs of each of these functional areas of utility business. However, the distribution rate component includes costs of many public policy programs that need to be paid for by all customers who use the utility distribution system.

General Rate Cases

Approximately 45% of the utilities' revenue requirements are set in Phase I of general rate cases (GRCs) at the CPUC and at FERC. GRC Phase II follows the completion of GRC Phase I and determines how to allocate revenue requirements to each customer class. The transmission revenue requirement is determined by the Federal Energy Regulatory Commission (FERC) in transmission owner rate cases following similar test year ratemaking.

The major components of costs that are reviewed and determined in the GRCs include Operations and Maintenance, Depreciation, Return on Rate Base, and Taxes. The revenue requirements for the 2010 General Rate Cases for the three major utilities are listed below.

2010 General Rate Case Revenue Requirements (000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,933,573	$1,978,951	$466,066
Depreciation	$1,148,688	$1,194,692	$316,259
Return on Rate Base	$909,993	$1,187,557	$251,958
Taxes	$617,138	$758,290	$178,960
Total	**$4,609,392**	**$5,119,489**	**$1,213,243**

(Excludes FERC determined transmission revenue requirements)

In December 2009, PG&E filed its test year 2011 GRC application which was reviewed by the Commission in 2010 and is currently in Phase 2 GRC proceedings. The Commission is considering PG&E's request and other parties' testimony on issues related to revenue allocation. The Commission will decide how PG&E will allocate the revenue requirement to each customer class to provide safe and reliable service at just and reasonable rates. SDG&E, SoCalGas, and SCE filed test year 2012 GRC applications in late 2010. The Commission is addressing similar issues in SCE, SDG&E, and SoCalGas GRC Phase I applications.

Electric Fuel and Purchased Power

Fuel and purchased power costs are handled by the Commission in two phases. In the first phase, the ERRA forecast phase, the Commission establishes PG&E's, SCE's, and SDG&E's revenue requirements to recover their costs for fuel for their power plants and to procure electricity under purchased power contracts. The Commission establishes an ERRA rate component based on a forecast of the costs and sales. In the second phase, the ERRA Reasonableness of Operations phase, the Commission determines the reasonableness of operations involving these fuel and purchased costs. These costs are passed through to customers without any mark-up or profit for the utility. Fuel and purchased power costs fluctuate with the market price of natural gas. Annual fuel and purchased power costs included in the utilities' electric rates for PG&E, SCE and SDG&E currently are $4.085 billion, $3.708 billion and $875 million respectively.

Utilities' actual fuel and purchased power costs, and the revenues they collect from customers to pay these costs, are tracked in a balancing account with interest. The account balance (difference between costs and revenues) is returned to customers if revenues exceed costs, or recovered from customers if costs exceed revenues, in a subsequent ERRA or other Commission proceeding. The costs shown above do not include ERRA account balances that are returned to or recovered from customers.

The Commission also has rules in place to ensure that the revenue requirement collected by the utilities tracks closely with the Commission's pre-specified market price benchmarks for gas and actual purchased power costs. If a utility's ERRA account balance exceeds 4% of its actual generation revenues in the prior year (i.e., the "trigger" level) and the balance is expected to exceed 5% of those revenues, the utility is generally required to file an expedited application to propose to amortize the balance in rates, resulting in a rate reduction. If the balance is expected to decline below the 4% trigger level within 120 days, the utility may inform the Commission of that fact by filing an advice letter and it is not required to file an expedited application in that event.

The Commission also reviews the utilities' energy procurement operations and purchased power contract administration activities for a prior annual period in a separate annual ERRA compliance proceeding for each utility. This allows the Commission to ensure that the utilities are prudently managing these activities.

Rate Related Proceedings in the Next 12 Months

Over the next 12 months, the Commission will review several requests filed by the utilities through formal applications and advice letters. Some of these proceedings are already filed and pending while others are likely to be filed later in the year.

Most of the proceedings are utility specific rate filings. However, two, Wildfire Insurance Costs and AB 32 Administrative Fee Recovery proceedings, are joint proceedings involving all the four major energy utilities.

Joint Utility Requests

Wildfire Insurance Costs

On August 2009, PG&E, SDG&E, SoCalGas, and SCE jointly filed Application 09-08-020 to request the establishment of a Wildfire Expense Balancing Account to record future recovery of uninsured wildfire costs. These costs include payments to third parties for damage or loss claims associated with wildfires, outside legal expenses associated with any third-party claims, payments to government authorities for fire suppression costs and environmental damage, and changes in wildfire premium amounts from the amount assumed in the last GRC. The utilities supported their request by citing significant increases in wildfire insurance premiums. For example, SDG&E's and SoCalGas's annual insurance premium that expired in June 2009 was $13.6 million; it had a liability limit of $1.2 billion, and a $1 million deductible. Their current annual premium is $55.2 million with a general liability limit of $800 million, a wildfire liability limit of $399 million, and a $35 million deductible for wildfires.

The assigned Commissioner and Administrative Law Judge issued a ruling in late 2009 following concerns that the utilities' proposal would provide no financial motivation to defend wildfire claims and that ratepayers would bear the cost of the claims with no practical means of defending the claims. The utilities filed an amended application mid 2010 to alleviate some of these concerns by setting limitations on the amount of wildfire damage or loss claims borne by ratepayers and increasing the amounts shareholders would absorb from such claims. However, the Assigned Commissioner and the Administrative Law Judge ruled that the application still failed to remedy the deficiencies outlined in the 2009 ruling. Presently, the application is suspended.

AB 32 Administrative Fee Recovery

PG&E, SDG&E, SoCalGas, and SCE jointly filed Application 10-08-002 with the Commission on August 2, 2010 to recover administrative fees paid to the California Air Resources Board (CARB) as a result of AB 32, the Global Warming Solutions Act. Under AB 32, California is required to reduce greenhouse gas emissions to 1990 levels by 2020. Under the legislation, CARB is required to adopt a schedule of fees to be paid by various sources of greenhouse gas. In late 2010, the Commission approved the utilities' request for regulatory accounts to record the AB 32 administration fees for later recovery and established a second phase of the proceeding to determine whether costs incurred prior to a utility's next GRC would be recoverable in rates.

Requested Recovery:

PG&E:	$4.8 million.
SCE:	$2.4 million
SDG&E:	$0.5 million
SoCalGas:	$4.5 million

Utility Specific Rate Requests

SCE

SCE has following applications with potential rate impacts pending before the Commission:

- **2009 ERRA Compliance A.10-04-002 (memorandum account recovery):** In this application, the Commission is reviewing various balancing and memorandum accounts for reasonableness and for compliance with Commission decisions and tariffs.

  Requested Recovery: $29.9 million which is associated with recovering costs recorded in four memorandum accounts.

- **CEMA Wind and Firestorm A.10-04-026:** SCE has requested to recover incremental O&M and capital revenue requirement associated with the 2007 wind and firestorms. Presently, SCE has filed a motion for the Commission to accept a settlement agreement that would reduce SCE's total requested recovery by $2.317 million.

  Requested Recovery: $10.6 million.

- **Demand Response Programs A.11-03-003:** On May 1, 2011 SCE filed application for approval of Demand Response (DR) programs, activities and budgets for the years 2012-2014. SCE aims to increase DR participation to 1,900 MW by 2014, aided by the full deployment of smart meters to all its customers, and to transform its DR program from being primarily reliability based to price responsive.

  Requested Recovery: $229 million.

- **Summer Discount Plan Program A.10-06-017:** In this application, SCE has requested rate recovery to implement a price responsive element into the Summer Discount Plan program so that the program could be bid into the California Independent System Operator's markets in order to achieve Demand Response objectives.

  Requested Recovery: $13 million.

- **2012 General Rate Case Phase 1 A.10-11-015:** SCE has requested an increase in revenue requirement for operation and maintenance as well as capital to replace aging infrastructure. In addition, SCE seeks increased revenue requirement to expand its system to accommodate increasing load.

  Requested Recovery: $6.285 billion. Amount represents an increase of $866 million over currently authorized base revenues.

SCE Rate Related Requests expected later this year

- **2012 ERRA Forecast:** In this application. which will be filed on August 1, 2011, the Commission will authorize the fuel and purchased power revenue requirement to be included in 2011 rate levels.

  Requested Recovery: Not known yet. Recovery amount depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in SCE's last ERRA decision and embedded in current rates is $3.708 billion. This filing will include the 2012 cost of various power purchase contracts that the Commission has already approved in the past. To the extent that the cost of 2012 power contracts is higher, this filing may request a higher amount than last year.

- **2010 ERRA Compliance:** SCE will file an application to seek recovery of costs recorded in various memorandum accounts for 2010.
- *Requested Recovery:* Not known yet.

- **DWR Revenue Requirement Determination**: Due to the termination in 2011 of the SCE allocated Sempra DWR contract and the established transfer payment schedule, SCE is anticipating a negative power charge in 2012. The 2012 bond and power charges will be allocated to SCE in late 2011 via the DWR revenue requirement determination in R.11-03-006, subject to approval by the Commission.

  Estimated Requested Recovery: Not known yet.

PG&E Rate Requests

PG&E has following rate requests pending before the Commission:

- **2009 ERRA Compliance Filing A.10-02-012 (MRTU):** PG&E filed an application on February 12, 2010 to recover costs incurred through the end of 2009 for compliance with the Market Redesign and Technology Upgrade initiative.

  Requested Recovery: $18.3 million.

- **Rate Design Window – Peak Time Rebate A.10-02-028:** PG&E requests approval of a two part peak time rebate pricing for residential customers to provide incentives for customers to shift peak time load usage during certain event days called by PG&E during the year.

  Requested Recovery: $33 million. None in 2011.

- **Default Residential Rate Programs – Peak Day Pricing A.10-08-005:** PG&E filed this application seeking to comply with D.08-07-045, Ordering Paragraph 8, whereby PG&E is required to propose a default peak day pricing proposal by August 9, 2010. PG&E seeks a deferral to introduce peak day pricing until PG&E's 2014 GRC. If its request is denied PG&E proposes a peak day price based on a four tier rate overlaid with time of use pricing with peak day pricing during certain event days.

  Requested Recovery: $141 million. None in 2011.

- **Demand Response Programs A.11-03-001:** On May 1, 2011 PG&E filed its application for approval of Demand Response (DR) programs, activities and budgets for the years 2012-2014.[5] For the program cycle 2012-2014, PG&E proposes to update its programs to be compatible with California Independent System Operator's (CAISO's) Proxy DR requirements, to modify its Base Interruptible Program so it can participate in the CAISO markets, leverage one of its programs to provide ancillary services and deliver an array of varied DR Programs.

  Requested Recovery: $234 million.

- **Pumped Storage Project A.10-08-011:** PG&E requests cost recovery for feasibility studies for federal hydropower project licensing.

  Requested Recovery: $33 million. None in 2011.

- **2011 Gas Transmission and Storage Rate Case A.09-09-013:** In April 2011, the CPUC approved a settlement that sets rates, terms and conditions of service for PG&E's gas transmission pipeline and storage business for the period 2011 to 2014. The proceeding is still open to consider certain gas safety measures.

  Requested Recovery: $514 million in 2011.

- **Silicon Valley Technology Center A.10-11-002:** Application seeks approval to support a photovoltaic manufacturing development facility in San Jose, California.

  Requested Recovery: $35.6 million.

- **Diablo Canyon Power Plant License Renewal A.10-01-022:** Request for authority to recover in rates $85 million in costs associated with obtaining the federal and state approvals required to seek a 20- year license renewal for Diablo Canyon Power Plant

[5] PG&E filed its Demand Response 2012-2014 application in A.11-03-001, SDG&E filed its application in A.11-03-002, and SCE filed its application in A.11-03-003.

Requested Recovery: $80 million. None in 2011.

- **ERRA 2010 Compliance Filing A.11-02-011 (MRTU):** Recovery of costs related to the Market Redesign and Technology Upgrade (MRTU) initiatives.

  Requested Recovery: $47.2 million.

- **2011 General Rate Case Phase 3 A.10-03-014:** Request includes $2.7 million in revenue requirements for new voluntary Real Time Pricing rate options, and $0.3 million in revenue requirements for Revised Customer Energy Statement.

  Requested Recovery: $3 million.

PG&E's rate related requests expected later this year

PG&E is expected to file the following rate related requests later this year. The requested amounts are not known at this time.

- Winter Gas Savings Program (2011-2012)
- Core Procurement Incentive Mechanism Shareholder Award
- Pipeline 2020
- FERC - TO14 (TY 2012)
- FERC TRBA/ECRA/RSBA Filing
- Public Purpose Program Surcharge Gas Rate Filing 2011 - Advice Letter
- SB 695 Res Rate Change (T1 & T2) Advice Letter
- Energy Resource Recovery Account (ERRA) 2012 Forecast – Requested Recovery depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in PG&E's last ERRA decision and embedded in current rates is $4.085 billion. This filing will include the 2012 cost of various power purchase contracts that the Commission has already approved in the past. To the extent that the 2012 cost of power contracts is higher, this filing may request a higher amount than last year.
- Annual Electric True-Up (AET) 2012 - Advice Letter Update
- Annual Gas True-Up (AGT) 2012 - Advice Letter Update
- FERC TACBA Filing

SDG&E Rate Requests

SDG&E has the following rate requests pending before the Commission:

- **ERRA Compliance Application A.10-06-001 (MRTU):** SDG&E seeks recovery of revenue requirement associated with balances in the Market Redesign and Technology Upgrade Memorandum Account, Procurement Transaction Auditing Memorandum Account, Independent Evaluator Memorandum Account, Generation Divestiture Transaction Cost Memorandum Account, and Renewables Portfolio Standard Memorandum Account (RPSMA).

  Requested Recovery: $4.32 million.

- **Rim Rock Tax Equity A.10-07-017:** SDG&E filed a petition for approval of a tax equity investment in the NaturEner Montana Wind Energy 3 (Rim Rock) in order to take advantage of Federal Production Tax Credits and produce more economic contract terms for ratepayers.

  Requested Recovery: $600 million.

- **Dynamic Pricing A.10-07-009:** SDG&E requests recovery of incremental costs to extend time varying rate options to small non-residential and residential customer classes.

  Requested Recovery: $118 million. $30 million is requested for 2011.

- **Demand Response Programs A. 11-03-003:** On May 1, 2011 SDG&E filed an application for approval of Demand Response (DR) programs, activities and budgets for the years 2012-2014. SDG&E seeks to develop its Demand Response portfolio, simplify its program, and promote automated controls to maximize customer response and enhance the reliability of Demand Response resources.

  Requested Recovery: $69 million.

- **2011 ERRA Forecast A.10-10-001:** SDG&E requests approval of revenue requirements to cover the costs of acquiring power for retail customers, including costs to purchase power under contracts with various power suppliers. Specifically, SDG&E requested authority to decrease ERRA and Competitive Transition Charge (CTC) rates.

  Requested Decrease: $56.1 milllion.

- **El Cajon Peaker A.11-01-004:** SDG&E requests approval of cost recovery for ownership and operation of the El Cajon 52 MW peaking facility.

  Requested Increase: $16.8 million.

- **2012 GRC Phase 1 A.10-12-005:** SDG&E requests an increase in revenue requirement for improvements in energy distribution system and increases in fire insurance premiums. The Commission will complete the review and approval process over the next 12 months.

  Requested Increase: $1.867 billion, an increase of $216 million over currently authorized base revenues.

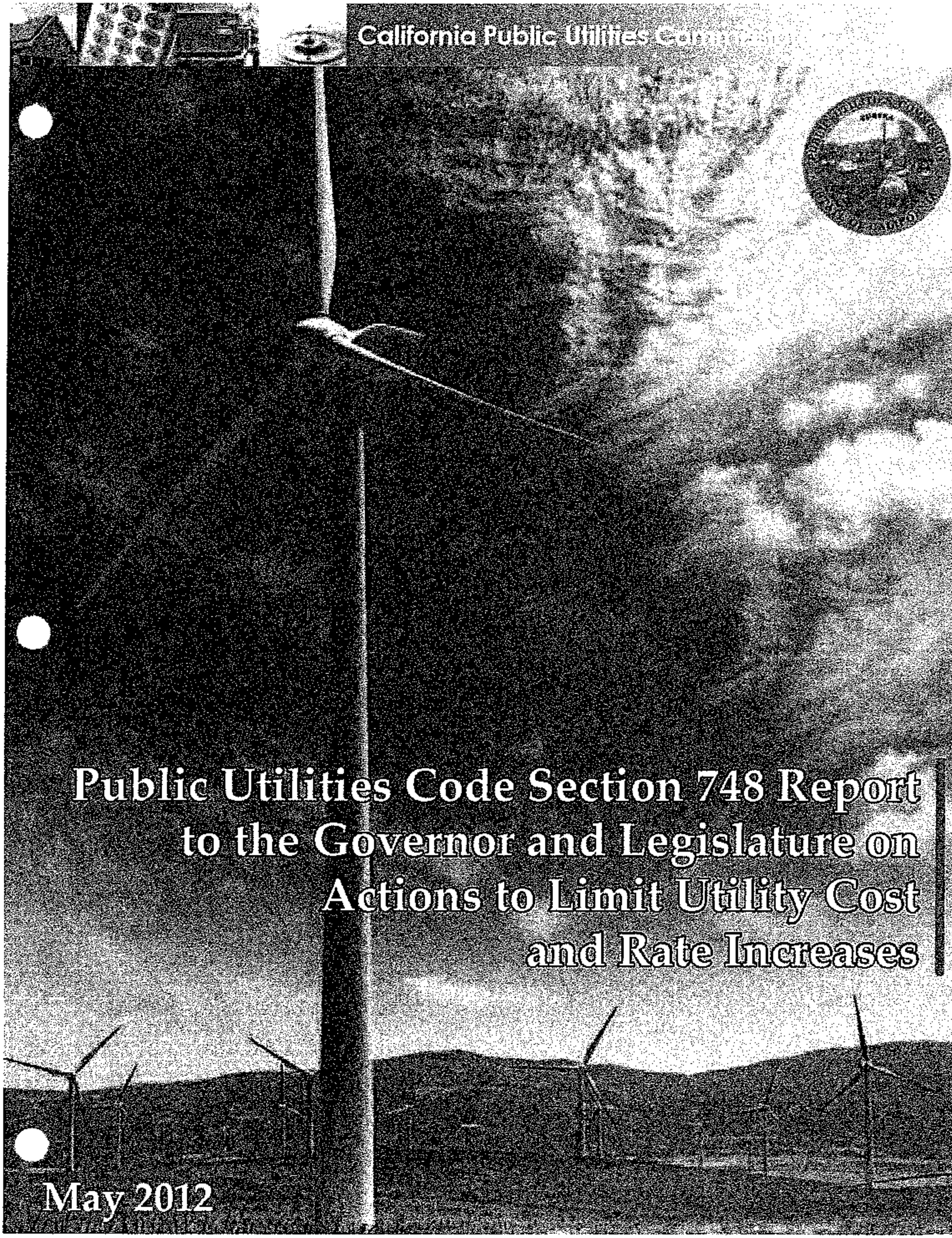
SDG&E rate related requests expected later this year

SDG&E is expected to file the following rate related requests later this year. The requested amounts are not known at this time.

- Demand Response Application
- Non-fuel generation balancing account update Advice Letter
- FERC Transmission Owner 3 true-up filing
- Electric Public Purpose Program Update Advice letter
- Energy Resource Recovery Account (ERRA) 2012 Forecast – SDG&E anticipates filing an application in October, 2011. Requested Recovery depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in

SDG&E's last ERRA decision and embedded in current rates is $875 million. This filing will include the 2012 cost of various power purchase contracts that the Commission has already approved in the past. To the extent that the 2012 cost of power contracts is higher, this filing may request a higher amount than last year.

- Electric Regulatory Account Update Advice letter
- SB 695 Residential Rate Change
- Electric Consolidated Advice letter
- FERC RS Filing
- FERC TACBAA/TRBAA Filing
- Z-Factor 2010-2012 Insurance Premiums Advice Letter
- DWR Implementation Advice Letter
- Gas Regulatory Account Update Advice Letter
- Gas Consolidated Advice Letter
- Gas Public Purpose Program Update Advice Letter
- Triennial Cost Allocation Proceeding: September 1, 2011
- Energy Efficiency Application
- CARE Application
- GRC Phase 2: September 1, 2011



California Public Utilities Commission

Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases

May 2012

ACA 11 - 00132

II. Electric Utility Costs and Revenue Requirements

Summary

Utilities file detailed descriptions of the costs of providing service (commonly referred to as revenue requirement to be collected from customers) in various proceedings and request the Commission to approve their proposed revenue requirement. The CPUC strives to balance the electric utility customers' needs for safe, reliable, and environmentally responsible service and the utilities' financial health, while achieving the lowest possible rates. Since energy services are essential, the CPUC ensures that access is universal and affordable. The bulk of utility revenue requirement is requested in General Rate Cases (GRCs) and the Energy Resource Recovery Account (ERRA) proceedings. GRCs address a utility's revenue requirement for maintaining and enhancing their generation and distribution infrastructure. ERRA costs are primarily fuel and purchased power costs which carry no mark-up or rate of return for the utility. In addition to the GRCs and ERRA proceedings, some costs are requested by the utilities in specific proceedings related to program areas such as energy efficiency, renewable portfolio standard (RPS), solar initiative, distributed generation and demand response, which are described in Chapter IV of this report.

Total Authorized Electric Revenue Requirements effective January 1, 2012 ($ Million)

PG&E	SCE	SDG&E
$12,370	$11,218	$3,005

The utilities file GRC applications every three or four years. Commission decisions on utilities' GRC applications establish revenue requirements for an initial forecast year (test year), and two or three subsequent "attrition years" to account for cost escalation during the GRC cycle.

PG&E, SCE, and SDG&E file ERRA forecast applications annually to recover fuel and purchased power costs expected during a future annual period. Each utility also files an annual ERRA compliance application to address actual ERRA costs incurred during a prior annual period. The ERRA proceedings were established by the Commission in 2002 in response to AB 57 (2001), which required that the utilities receive timely recovery of their electricity procurement costs.

All of the Commission-approved GRC and ERRA costs are recovered through two main types of rate charges -- generation and distribution -- which appear on customer bills as separate line items. Transmission-related costs and revenue requirements are under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and are recovered in the transmission component of rates. The grouping of rates into generation, distribution, and transmission is primarily based on the costs of each of these functional areas of utility business. However, the distribution rate component includes costs of many public policy programs that should be paid for by all customers who use the utility distribution system.

Requests for Revenue Requirement Increases Under CPUC Consideration in 2012

Electricity General Rate Cases

The major components of costs that are reviewed and determined in the GRCs include operations and maintenance, depreciation, return on rate base, and taxes. The revenue requirements for 2011 authorized by the Commission in recent GRCs for the three major utilities are listed below.

2011 Authorized Electric General Rate Case Revenue Requirements ($ Million)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,947	$1,951	$480
Depreciation	$1,099*	$1,037	$216
Return on Rate Base	$1,246	$1,117	$242
Taxes	$734	$724	$171
Attrition **		$424	$103
Total	**$5,026**	**$5,254**	**$1,212**

* Includes $38 million for fossil and nuclear decommissioning.
** PG&E's attrition allowances apply to years 2012 and 2013; SCE's attrition includes amounts authorized for 2010 and 2011; SDG&E's attrition includes amounts authorized for 2009, 2010, and 2011.

In May 2011, the Commission adopted PG&E's test year 2011 GRC revenue requirement which is shown in the table above. As part of the 2011 GRC decision, the Commission authorized PG&E an attrition increase in 2012 of $145 million, so PG&E's GRC revenue requirement for 2012 is $5,171 million. In the 4th quarter of 2012, PG&E will file its test year 2014 GRC. The Commission will address PG&E's GRC application during 2012 and a decision is expected at the end of 2013 or in early 2014.

SCE filed its 2012 GRC in November 2010 requesting a 2012 GRC revenue requirement of $6,214 million. This represents an increase of about $800 million or 7% of total authorized revenues. According to SCE, the increase is needed to accommodate increased customer and load growth, replace aging distribution infrastructure, make contributions to employee pension funds, and for other projects needed to operate its system. The Commission is expected to adopt a decision in the revenue requirements phase in the 2nd quarter of 2012.

SDG&E filed its 2012 GRC application in December 2010 requesting a 2012 electric GRC revenue requirement of $1,523 million. This represents an electric revenue increase of about $260 million or 9% of total authorized revenues. According to SDG&E, the increase is needed for distribution capital investments, insurance premiums, and other projects needed to operate its system. The Commission is expected to adopt a decision in the revenue requirements phase in the 3rd quarter of 2012.

After the Commission reviews and determines the utility's authorized revenues, the Commission begins a Phase 2 of each General Rate Case. In this rate design phase, parties propose and the Commission considers the various methods of allocating the total authorized revenue among the different classes of ratepayers, and methods of designing the specific rates the utility should use to collect its authorized revenue requirement. As discussed in more detail in Chapter 3 under "Time Variant Pricing", the specific rate design proceedings currently under consideration by the Commission.

Forecasting Electric Fuel and Purchased Power Costs

The Commission establishes PG&E's, SCE's, and SDG&E's revenue requirements to recover their costs for fuel for their power plants and to procure electricity under purchased power contracts in the annual ERRA forecast proceeding. The Commission establishes an ERRA rate component based on a forecast of the costs, which are passed through to customers without any mark-up or profit for the utility. Fuel and purchased power costs fluctuate with the market price of natural gas. The utilities' current authorized annual revenue requirements to recover fuel and purchased power costs adopted in Commission ERRA forecast proceedings are shown below.

Annual Electric Revenue Requirements for Fuel and Purchased Power Costs ($ Million)

PG&E	SCE	SDG&E
$3,990	$3,708	$829
Effective Jan. 2012	Effective June 2011	Effective Sept. 2011

PG&E's 2012 ERRA forecast proceeding was concluded last December, resulting in the fuel and purchased power revenue requirement shown above. SCE is requesting a fuel and purchased power revenue requirement of $4,017 million for 2012. A Commission decision in SCE's 2012 ERRA forecast proceeding is expected in the 2nd quarter. SDG&E requested a fuel and purchased power revenue requirement of $953 million, later amended to $871 million, for 2012. A Commission decision in SDG&E's 2012 ERRA forecast proceeding is expected in the 3rd quarter of this year.

Utilities' actual fuel and purchased power costs, and the revenues they collect from customers to pay these costs, are tracked in a balancing account with interest and addressed in subsequent ERRA or related Commission proceeding. In the event that the revenues exceed the costs, then the account balance (difference between costs and revenues) is returned to the customers. If the costs exceed the revenues then the costs are recovered from customers. The costs shown above do not include ERRA account balances that are returned to or recovered from customers.

The Commission also has rules in place to ensure that the revenue requirement collected by the utilities tracks closely with the Commission's pre-specified market price benchmarks for gas and actual purchased power costs. If a utility's ERRA account balance exceeds 4% of its actual generation revenues in the prior year (i.e., the "trigger" level) and the balance is expected to exceed 5% of those revenues, the utility is generally required to file an expedited application to propose to amortize the balance in rates, resulting in a rate reduction. If the balance is expected to decline below the 4% trigger level within 120 days, the utility may inform the Commission in an advice letter, but is not required to file an expedited application.

Electric Fuel and Purchased Power – Review of Actual Costs

The Commission also reviews each utility's energy procurement operations and purchased power contract administration activities for a prior annual period in a separate annual ERRA compliance proceeding for each utility. This allows the Commission to ensure that the utilities are prudently managing these costs. In 2011, the Commission issued decisions in PG&E's, SCE's and SDG&E's ERRA 2010 compliance proceedings, which addressed fuel and purchased power costs and operations during 2009. The Commission determined that the utilities' dispatching operations, power contract administration, and fuel and purchased power costs incurred during 2009 were prudent. Likewise, in 2011, the utilities filed ERRA compliance applications addressing energy costs and operations during 2010, and the Commission will issue decisions in these applications in 2012. PG&E and SCE filed ERRA compliance applications in February and April 2012, respectively, addressing 2011 energy costs and operations, with decisions anticipated in 2013.

Plans to Improve Commission Efficacy in Ratemaking

A Heightened Focus on Safety and Accountability

In the GRC, a utility must present detailed evidence regarding how much revenue it needs to safely and reliably operate its system. After reviewing the utility's request, the Commission establishes an authorized revenue requirement which is included in rates for the GRC cycle.

If the utility spends more than the revenue authorized in the GRC, it absorbs the excess costs. If the utility spends less than authorized it is allowed to retain the revenue, but the spending reductions will be reflected in the next GRC cycle since authorized revenues are based in part on historic spending levels. This is intended to provide an incentive to the utility to manage its operations efficiently and reduce costs where possible.

The utility has discretion to reprioritize projects approved for funding in the GRC, and defer spending in certain areas in favor of spending on other activities to ensure safe and reliable service. In the wake of the 2010 San Bruno tragedy, the Commission is reexamining its ratemaking processes with a primary focus on safety and risk management.

In its decision in PG&E's 2011 GRC, the Commission emphasized that the utility has the responsibility to spend what is necessary to ensure safe and reliable service despite any financial implications of exceeding authorized cost levels. The Commission required PG&E to submit reports on authorized revenues versus actual expenditures for major electric and gas work categories, including explanations of significant differences between authorized and recorded spending for each category.

In January 2012, the Commission held a workshop to initiate discussion among all gas and electric utility stakeholders on how to improve the ratemaking process to focus on safety. There will be a follow-up to this workshop, which may include a new rulemaking to address changes to GRC ratemaking.

Consolidated Review of Market Redesign and Technology Upgrade Costs

In 2007 the Commission allowed PG&E, SCE, and SDG&E to establish memorandum accounts to record costs for implementing the California Independent System Operator's (CAISO) Market Redesign and Technology Upgrade (MRTU) initiative. Costs recorded in these memorandum accounts through 2009 were reviewed by the Commission separately for each utility in their ERRA compliance proceedings.

To identify best practices and to clearly identify and compare cost differences among the utilities, in 2011 the Commission required PG&E, SCE, and SDG&E to jointly file applications addressing costs incurred for implementing the CAISO's MRTU initiative. Costs recorded in the MRTU memorandum accounts from 2010 and beyond will be reviewed by the Commission in the consolidated proceeding initiated in 2011. In January 2012 the utilities filed their joint application on 2010 MRTU costs, A.12-01-014, requesting a total recovery of approximately $85 million in MRTU costs recorded in 2010.

Other Rate Related Proceedings in the Next 12 Months

Over the next 12 months, the Commission will review several requests filed by the utilities through formal applications and advice letters. Some of these proceedings are already filed and pending while others are likely to be filed later in the year. Most of the proceedings are utility specific rate filings. However, the first five proceedings described below are joint proceedings involving all or several of the four major energy utilities.

Joint Utility Requests

- **Wildfire Insurance Costs**

  PG&E, SDG&E, SoCalGas, and SCE jointly filed A.09-08-020 to request balancing accounts to record uninsured wildfire costs for possible future recovery. An Assigned Commissioner's Ruling in January, 2012 granted the motion of PG&E and SCE to withdraw from this case, and denied their motion to retain their associated memorandum accounts. SDG&E and SoCalGas are still pursuing this application. Briefs were filed in February and March 2012.

- **AB 32 Administrative Fee Recovery**

  D.10-12-026 (A.10-08-002) authorized PG&E, SCE, SDG&E, and SoCalGas to establish memorandum accounts to record the costs of this administrative fee assessed by CARB. The decision does not prejudge any issues regarding recovery by the utilities of these costs. Briefs were filed in October 2011, and the case was submitted to the Commission.

- **Cost and Revenue Issues associated with GHG Emissions**

  The Commission opened R.11-03-012 to address potential utility cost and revenue issues associated with greenhouse gas (GHG) emissions. The initial focus of the rulemaking is how to use revenues that electric utilities may generate from auction of allowances allocated to them by the California Air Resources Board (CARB), how to use revenues that electric utilities may receive from sale of Low Carbon Fuel Standard credits they may receive from CARB, and the treatment of possible GHG compliance costs associated with electricity procurement. In

January 2012, parties filed proposals on the appropriate use of GHG allowance auction revenues, and in March parties filed proposals on allocating revenue from the sale of low carbon fuel standard credits. Proposed decisions in these two portions of the proceeding are scheduled to be issued in June and October 2012, respectively.

- **Annual Revenue Requirement Determination of Department of Water Resources**

  The Commission opened R.11-03-006 to consider issues related to the annual revenue requirement determination of the California Department of Water Resources (DWR) in connection with its procurement of energy for the electricity customers of PG&E, SCE, and SDG&E. Each year around August, DWR submits its revenue requirement for the following year to the Commission for adoption and subsequent collection from ratepayers through the DWR Power Charge. A proposed decision allocating the 2012 DWR revenue requirement and refunds from two lawsuit settlement agreements was issued on April 3, 2012.

- **Funding and Program Issues Related to Renewables and RD&D**

  Funding authorized in Public Utilities Code Section 399.8, which governs the system benefits charge, expired as of January 1, 2012. Public benefits provided by the expired funding are in the areas of energy efficiency, renewable energy, and research, development, and demonstration (RD&D). The Commission opened R.11-10-003 to address funding and program issues related to the renewables and RD&D portions of the expiring public goods charge funding.

  Requested Revenue: PG&E; 2012--$70 million, 2013--$25 million.

Common Utility-Specific Rate Requests

- **Future ERRA Forecast Applications**
  - **PG&E 2013 ERRA Forecast:** This application will be filed in June, 2012.
  - **SCE 2013 ERRA Forecast:** This application will be filed in August, 2012.
  - **SDG&E 2013 ERRA Forecast:** This application will be filed in September, 2012.

- **ERRA Compliance Review Applications**
  - **General:** In these applications, the Commission reviews each utility's energy procurement and purchased power contract administration for a prior year.
  - **PG&E 2010 ERRA Compliance A.11-02-011:** Recovery of costs related to the Market Redesign and Technology Upgrade (MRTU) initiatives, and other procurement-related costs.

    Requested Recovery: $47.2 million.

  Pursuant to ALJ ruling in this case, PG&E moved its request for $47.2 million for MRTU costs from this case to A.12-01-014, joint application by PG&E, SCE, and SDG&E for costs associated with MRTU. Briefs were filed in March and April 2012 on issues remaining in this ERRA compliance case.

  - **PG&E 2011 ERRA Compliance A.12-02-010:** Application seeks recovery of costs recorded in PG&E's Renewables Portfolio Standard memorandum account for 2011.

- **SCE 2010 ERRA Compliance A.11-04-001:** In this application, the Commission is reviewing procurement-related operations during 2010, as well as other memorandum accounts for reasonableness and for compliance with Commission decisions and tariffs.

  Requested Recovery: $25.6 million which is associated with recovering costs recorded in three memorandum accounts.

- **SCE 2011 ERRA Compliance A.12-04-001:** Application seeks recovery of costs recorded in various memorandum accounts for 2011.

  Requested Recovery: Reduction of $26.8 million.

- **SDG&E 2010 ERRA Compliance Application A.11-06-003:** SDG&E seeks recovery of revenue requirement associated with fuel and purchased power costs as well as balances in various memorandum accounts.

  Requested Recovery: $2.2 million.

➢ <u>SB 695 Residential Rate Change</u>

- General: Advice Letters to be filed in November, 2012 to propose annual increase in residential Tiers 1 and 2 rates with corresponding decrease in Tiers 3 and 4 rates, as allowed under SB 695.

Recently Decided or Pending Cases

➢ <u>PG&E</u>

- **Silicon Valley Technology Center A.10-11-002:** Application seeks approval to support a photovoltaic manufacturing development facility in San Jose, California. The ALJ issued a PD denying this application on February 7, 2012, and an Alternate PD was issued on the same date approving this application and a revenue requirement of $16.9 million.

  Requested Recovery: $35.6 million.

- **Modifications to the SmartMeter Program A.11-03-014:** PG&E filed this application in response to a directive from Commission President Peevey to prepare a proposal for Commission consideration that would allow opt-out by residential customers who object to having an advanced, digital meter that communicates using radio frequency signals. D.12-02-014 adopted an advanced meter opt-out provision along with procedures and interim fees for customers who choose to opt-out and use analog meters. It also determined that a second phase in this proceeding would be necessary to consider cost and cost allocation issues for providing the analog meter opt-out option.

  Estimated Recovery: $113 million.

- **Diablo Canyon Seismic Studies Costs, A.11-01-014:** Request to spend $64 million on seismic studies.

- **California Solar Initiative, D.11-12-019:** Approved 2012 CSI revenue requirement for PG&E of $120 million (increase of $15 million) is pending next regularly scheduled electric and gas rates changes. The 2013 CSI revenue requirement of $85 million will be reflected in rates in early 2013.

➢ SCE

- **California Solar Initiative, D.11-12-019:** Approved 2012 CSI revenue requirement of $110 million, unchanged from 2011, and 2013 revenue requirement of $74 million, which will reduce rates by $36 million.

➢ SDG&E

- **Rim Rock Tax Equity, A.10-07-017:** SDG&E filed an application for approval of a tax equity investment in the NaturEner Montana Wind Energy 3 (Rim Rock) in order to take advantage of Federal Production Tax Credits and produce more economic contract terms for ratepayers. D.11-07-002 approved a settlement in the case. The associated revenue requirement will take effect when the Rim Rock project is put into commercial operation, anticipated to be late 2012.

  Requested Recovery: $21.9 million annual revenue requirement.

Other Rate-Related Utility Requests Expected Later This Year

➢ PG&E

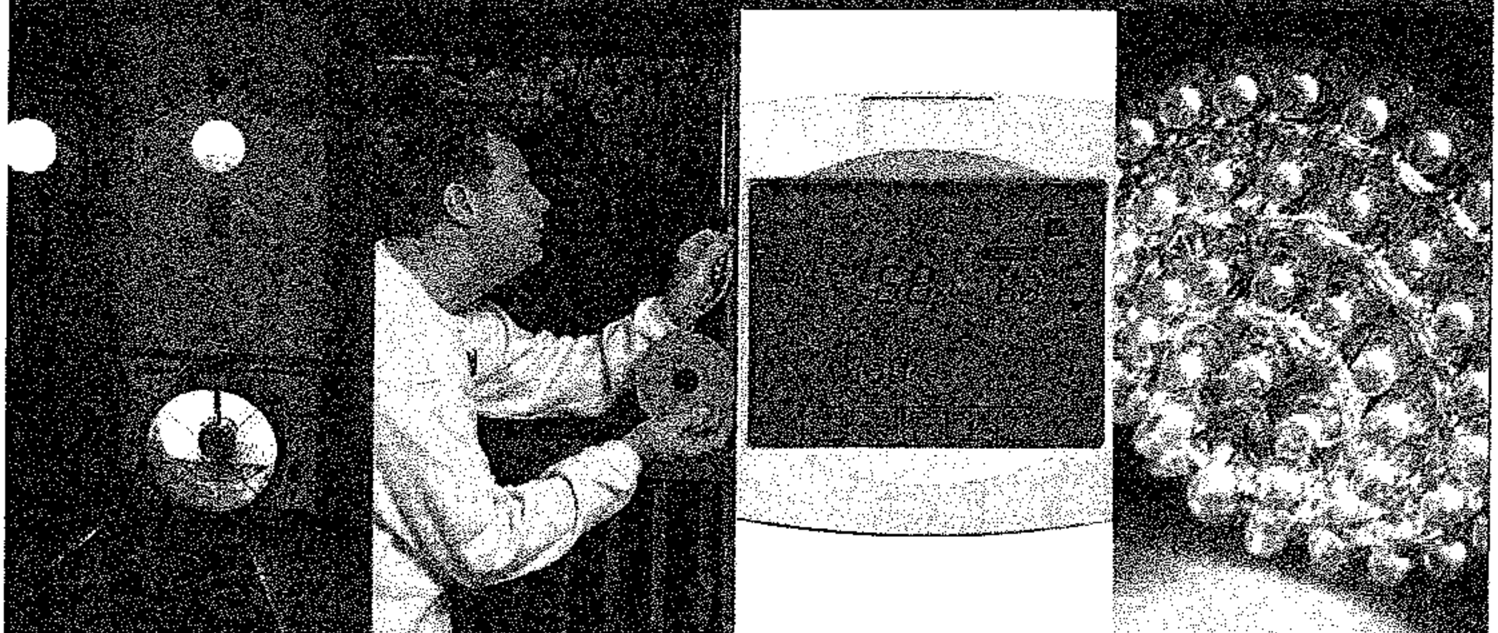
- **Energy Efficiency 2013-2014 Bridge Funding:** to be filed in April, 2012.
- **Annual Electric True-Up (AET) 2013:** Advice Letter to be filed late this year; to adjust for balancing account over-/under-collections and the effects of other decisions.

➢ SDG&E

- **Non-fuel generation balancing account update Advice Letter**
- **Electric Regulatory Account Update Advice letter**
- **Electric Consolidated Advice Letter**

California Public Utilities Commission

Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases



June 2013

II. Electric Utility Costs and Revenue Requirements

Utilities file detailed descriptions of the costs of providing service (commonly referred to as revenue requirements to be collected from customers) in various proceedings and request the CPUC to approve their proposed revenue requirement. The CPUC strives to balance the electric utility customers' needs for safe, reliable, and environmentally responsible service and the utilities' financial health, while achieving the lowest possible rates. Since energy services are essential, the CPUC ensures that access is universal and affordable. The bulk of utility revenue requirement is requested in General Rate Cases (GRCs) and the Energy Resource Recovery Account (ERRA) proceedings. GRCs address a utility's revenue requirement for maintaining and enhancing their generation and distribution infrastructure. ERRA costs are primarily fuel and purchased power costs which carry no mark-up or rate of return for the utility. In addition to the GRCs and ERRA proceedings, some costs are requested by the utilities in specific proceedings related to program areas such as energy efficiency, renewables portfolio standard (RPS), California Solar Initiative (CSI), distributed generation (DG) and demand response (DR), which are described in other chapters of this report.

Table II-1
Total Authorized Electric Revenue Requirements effective January 1, 2013
($ Million)

PG&E	SCE	SDG&E
$12,370	$12,015	$3,141

The utilities file GRC applications every three or four years. CPUC decisions on utilities' GRC applications establish revenue requirements for an initial forecast year (test year), and two or three subsequent "attrition years" to account for cost escalation during the GRC cycle.

PG&E, SCE, and SDG&E file ERRA forecast applications annually to recover fuel and purchased power costs expected during a future annual period. Each utility also files an annual ERRA compliance application to address actual ERRA costs incurred during a prior annual period. The ERRA proceedings were established by the CPUC in 2002 in response to AB 57 (2001), which required that the utilities receive timely recovery of their electricity procurement costs.

All of the CPUC-approved GRC and ERRA costs are recovered through two main types of rate charges -- generation and distribution -- which appear on customer bills as separate line items. Transmission-related costs and revenue requirements are under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and are recovered in the transmission component of rates. The grouping of rates into generation, distribution, and transmission is primarily based on the costs of each of these functional areas of utility business. However, the distribution rate component includes costs of many public policy programs that should be paid for by all customers who use the utility distribution system.

A more detailed description of how utility revenue requirements are established can be found in the 2013 AB 67 Report.[2]

A. Requests for Revenue Requirement Increases Under CPUC Consideration

1. Electricity General Rate Cases

The major components of costs that are reviewed and determined in the GRCs include operations and maintenance, depreciation, return on rate base, and taxes. The revenue requirements for 2013 authorized by the CPUC in recent GRCs for the three major utilities are listed below.

Table II-2
2013 Authorized Electric General Rate Case Revenue Requirements ($ Million)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,947	$2,272	$659
Depreciation	$1,099*	$1,222	$274
Return on Rate Base	$1,246	$1,465	$300
Taxes	$734	$712	$207
Attrition **	$295	$358	$40
Total	**$5,321**	**$6,029**	**$1,481**

* Includes $38 million for fossil and nuclear decommissioning.
** PG&E's attrition allowances apply to years 2012 and 2013; attrition for both years is shown above. SCE's attrition allowances apply to years 2013 and 2014; only the 2013 attrition amount is shown above. SDG&E's attrition allowances apply to years 2013 – 2015; only the 2013 attrition amount is shown above and is estimated to be $40 million, 2.75% of the 2012 authorized GRC revenue requirement, based on the attrition mechanism (CPI-urban index plus 75 basis points) adopted for SDG&E in its 2012 GRC.

PG&E 2014 GRC: PG&E's authorized 2013 GRC revenue requirement is $5,321 million, as authorized by the CPUC in the 2011 GRC. In November 2012, PG&E filed its 2014 GRC application. PG&E is seeking an increase of $796 million over the currently authorized electric revenue requirement in that case. PG&E cites safety and reliability related reasons for its requested increase including the need for investments in its electric distribution system, and expenditures on its nuclear and hydroelectric facilities. The CPUC will address PG&E's GRC application during 2013, with a decision expected at the end of 2013 or in early 2014.

SCE 2012 GRC: In November 2012, the CPUC authorized a 2012 revenue requirement of $5,671 million for SCE. This represented an increase of $272 million over 2011 rates, roughly a 5% increase. The CPUC also authorized an attrition increase of $358 million in 2013, and an increase of $356 million in 2014. The increases are needed to accommodate increased customer and load growth, replace aging distribution infrastructure, and the continuing need to provide safe and reliable service. SCE will file its 2015 GRC application in the 4th quarter of 2013, and the CPUC will review SCE's 2015 GRC in 2014.

[2] Electric and Gas Utility Cost Report to the Governor and Legislature, available at http://www.cpuc.ca.gov/NR/rdonlyres/26E020D9-D7D1-45B3-A637-0E89456F1F9C/0/AB67CostReport201204252013.pdf

SDG&E 2012 GRC: In May 2013, the CPUC authorized a 2012 revenue requirement of $1,441 million for SDG&E. This represented an increase of $115 million over 2011 rates, roughly an 8.7% increase. The CPUC also authorized an attrition increase of $40 million in 2013 and an increase of $41 million in 2014. These increases are needed for distribution capital investments, insurance premiums, and other projects needed to operate SDG&E's system in a safe and reliable manner. The CPUC authorized SDG&E to file its next GRC in late 2014 for test year 2016.

2. Electric Fuel and Purchased Power Costs

The CPUC establishes PG&E's, SCE's, and SDG&E's revenue requirements to recover their costs for fuel for their power plants and to procure electricity under purchased power contracts in the annual ERRA forecast proceeding. The CPUC establishes an ERRA rate component based on a forecast of the costs, which are passed through to customers without any mark-up or profit for the utility. Fuel and purchased power costs fluctuate with the market prices.

Utilities' actual fuel and purchased power costs, and the revenues they collect from customers to pay these costs, are tracked in a balancing account and addressed in a subsequent ERRA or related CPUC proceeding. In the event that the revenues exceed the costs, then the account balance (difference between costs and revenues) is returned to the customers. If the costs exceed the revenues then the costs are recovered from customers.

The CPUC also has rules in place to ensure that the revenue requirement collected by the utilities tracks closely with the CPUC's pre-specified market price benchmarks for gas and actual purchased power costs. If a utility's ERRA account balance exceeds 4% of its actual generation revenues in the prior year (i.e., the "trigger" level) and the balance is expected to exceed 5% of those revenues, the utility is generally required to file an expedited application to propose to amortize the balance in rates, resulting in a rate reduction. If the balance is expected to decline below the 4% trigger level within 120 days, the utility may inform the CPUC in an advice letter, but is not required to file an expedited application.

The utilities' current authorized annual revenue requirements to recover fuel and purchased power costs adopted in the CPUC's ERRA forecast proceedings are shown below.

Table II-3
Annual Electric Revenue Requirements for Fuel and Purchased Power Costs
($ Million)

PG&E	SCE	SDG&E
$4,377	**$3,672**	**$1,052**
Effective Jan. 2013	**Effective Aug. 2012**	**Effective Jan. 2013**

PG&E's ERRA: In December 2012 the CPUC approved PG&E's fuel and purchased power revenue requirement for 2013 as shown above. In June 2013 PG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2014.

SCE's ERRA: In August 2012 SCE filed its 2013 ERRA application in which it requests a fuel and purchased power revenue requirement of $4,520 million for 2013. A CPUC decision in that case is expected in the 2nd quarter of 2013. SCE will file its ERRA application for 2014 fuel and purchased power costs in August 2013.

SDG&E's ERRA: SDG&E is requesting a fuel and purchased power revenue requirement of $1,057 million in its pending 2013 ERRA forecast proceeding. A CPUC decision in that case is expected in the 3rd quarter of 2013. SDG&E will file its ERRA application for 2014 fuel and purchased power costs in October 2013.

The CPUC also reviews each utility's energy procurement operations and purchased power contract administration activities for a prior annual period in a separate annual ERRA compliance proceeding for each utility.

a) Investigation of the Outage at the San Onofre Nuclear Generating Station

Units 2 and 3 at the San Onofre Nuclear Generating Station (SONGS) have been shut down since January 2012 due to problems with new steam generators that were recently installed. SCE owns about 78% of SONGS and operates the plant; SDG&E owns 20%, and the remaining share is owned by the City of Riverside. SCE manages SONGS and has recently announced that it plans to permanently shut down SONGS.

In late 2012 the CPUC opened an investigation to consider removing the plant from SCE's and SDG&E's rate base and to review the steam generator replacement project costs. As of Jan 1, 2013, SCE is collecting more than $600 million in rates for owning and operating the plant. These costs as well as SDG&E's share of SONGS costs in rates will be reviewed by the CPUC for reasonableness in the CPUC's investigation and could be refunded to ratepayers.

B. Plans to Improve CPUC Efficacy in Ratemaking

The CPUC has committed to improving the efficacy of its rulemakings, particularly in the areas of safety and accountability.

A utility must present in its GRCs detailed evidence regarding how much revenue it needs to safely and reliably operate its system. After reviewing the utility's request, the CPUC establishes an authorized revenue requirement which is included in rates for the GRC cycle.

If the utility spends more than the revenue authorized in the GRC, it absorbs the excess costs. If the utility spends less than authorized it is allowed to retain the revenue, but the spending reductions will be reflected in the next GRC cycle since authorized revenues are based in part on historic spending levels. This is intended to provide an incentive to the utility to manage its operations efficiently and reduce costs where possible.

The utility has discretion to reprioritize projects approved for funding in the GRC, and defer spending in certain areas in favor of spending on other activities to ensure safe and reliable service. In the wake of the 2010 San Bruno tragedy, the CPUC is reexamining its ratemaking processes, focusing primarily on safety and risk management.

In its decision in PG&E's 2011 GRC, the CPUC emphasized that the utility has the responsibility to spend what is necessary to ensure safe and reliable service despite any financial implications of exceeding authorized cost levels. The CPUC required PG&E to submit reports on authorized revenues versus actual expenditures for major electric and gas work categories, including explanations of significant differences between authorized and recorded spending for each category. Similar reporting requirements were required by the CPUC in SCE's 2012 GRC.

In PG&E's 2014 GRC the CPUC has required that independent consultants hired by the Safety and Enforcement Division evaluate risk assessments, risk mitigation, programs and policies, as well as PG&E's corporate policies, goals, culture, and efforts being made to bolster system safety and security.

C. Other Rate Related Proceedings in the Next 12 Months

Over the next 12 months, the CPUC will review several requests filed by the utilities through formal applications and advice letters. Details of the formal applications are provided in the Appendix, which contains tables of the current and anticipated proceedings, with descriptions and case numbers. Two proceedings worth noting and discussed below are the smart meter opt-out proceeding and the annual revenue requirement determination of the Department of Water Resources.

1. Annual Revenue Requirement Determination of Department of Water Resources

The CPUC opened R.13-02-019 to consider issues related to the annual revenue requirement determination of the California Department of Water Resources (DWR) in connection with its procurement of energy for the electricity customers of PG&E, SDG&E and SCE. In August, 2013, CDWR is expected to file its 2014 revenue requirement and a CPUC decision will be issued in December 2013. The CPUC's approval and allocation of DWR revenue requirements will affect the rates of PG&E, SDG&E and SCE customers.

2. Modifications to the SmartMeter Program

In A.11-03-014, A.11-03-015, A.11-07-020, PG&E, SCE and SDG&E filed applications to give residential customers the option to opt out of the SmartMeter program. After addressing the legal issues in Phase I, the CPUC adopted D.12-02-014, which sets forth an advanced meter opt-out provision along with procedures and interim fees for opting out. In April 2012, the assigned commissioner ruled to consolidate the SmartMeter opt-out applications within a single proceeding and to consider in Phase II all cost and cost allocation issues. The CPUC held evidentiary hearings in November 2012, and the parties filed opening and reply briefs in January 2013. The IOUs' updated fee proposals are for initial fees ranging from $75 to $189, monthly fees ranging from $10 to $24, and exit fees ranging from $43 to $90. A decision is expected later this year.

Actions to Limit Utility Cost and Rate Increases in Compliance with Public Utilities Code 748

ENERGY DIVISION
REPORT TO THE GOVERNOR AND LEGISLATURE

June 2014

I. Electric Utility Costs and Revenue Requirements

A. Work Area

Utilities file detailed descriptions of the costs of providing service (commonly referred to as revenue requirements to be collected from customers) in various proceedings and request the CPUC to approve their proposed revenue requirement. The CPUC strives to balance the electric utility customers' needs for safe, reliable, and environmentally responsible service and the utilities' financial health, while achieving the lowest possible rates. Since energy services are essential, the CPUC ensures that access is universal and affordable. The bulk of utility revenue requirement is requested in General Rate Cases (GRCs) and the Energy Resource Recovery Account (ERRA) proceedings. GRCs address a utility's revenue requirement for maintaining and enhancing their generation and distribution infrastructure. ERRA costs are primarily fuel and purchased power costs which carry no mark-up or rate of return for the utility. In addition to the GRCs and ERRA proceedings, some costs are requested by the utilities in specific proceedings related to program areas such as energy efficiency, renewables portfolio standard (RPS), California Solar Initiative (CSI), distributed generation (DG) and demand response (DR), which are described in other chapters of this report.

Table II-1
Total Authorized Electric Revenue Requirements effective January 1, 2014
($ Million)

PG&E	SCE	SDG&E
$13,032	$12,063	$3,545

The utilities file GRC applications every three or four years. CPUC decisions on utilities' GRC applications establish revenue requirements for an initial forecast year (test year), and two or three subsequent "attrition years" to account for cost escalation during the GRC cycle.

PG&E, SCE, and SDG&E file ERRA forecast applications annually to recover fuel and purchased power costs expected during a future annual period. Each utility also files an annual ERRA compliance application to address actual ERRA costs incurred during a prior annual period. The ERRA proceedings were established by the CPUC in 2002 in response to AB 57 (2001), which required that the utilities receive timely recovery of their electricity procurement costs.

All of the CPUC-approved GRC and ERRA costs are recovered through two main types of rate charges -- generation and distribution -- which appear on customer bills as separate line items. Transmission-related costs and revenue requirements are under the jurisdiction of the Federal

Energy Regulatory Commission (FERC) and are recovered in the transmission component of rates. The grouping of rates into generation, distribution, and transmission is primarily based on the costs of each of these functional areas of utility business. However, the distribution rate component includes costs of many public policy programs that should be paid for by all customers who use the utility distribution system.

A more detailed description of how utility revenue requirements are established can be found in the 2014 AB 67 Report.[3]

B. Activities and Proceedings in the next 12 months

1. Electricity General Rate Cases

The major components of costs that are reviewed and determined in the GRCs include operations and maintenance, depreciation, return on rate base, and taxes. The revenue requirements for 2014 authorized by the CPUC in recent GRCs for the three major utilities are listed below.

Table II-2
2014 Authorized Electric General Rate Case Revenue Requirements ($ Million)

	PG&E*	SCE	SDG&E
Operations and Maintenance	$2,202	$2,272	$658
Depreciation	$1,800**	$1,222	$274
Return on Rate Base	$1,008	$1,465	$300
Taxes	$451	$712	$207
Attrition***		$478	$79
Total	**$5,461**	**$6,149**	**$1,518**

* The revenue requirements shown for PG&E do not reflect any increases proposed by PG&E in its pending 2014 GRC Application. The CPUC is expected to issue a decision in that case in the 2nd quarter of 2014.

**Includes $36 million for fossil decommissioning.

*** SCE's attrition allowances apply to years 2013 and 2014; attrition for both years is shown above. SDG&E's attrition allowances apply to years 2013 – 2015; attrition for years 2013 and 2014 is shown above.

[3] Electric and Gas Utility Cost Report to the Governor and Legislature, available at ____________

a) PG&E 2014 GRC

In November 2012, PG&E filed its 2014 GRC application. PG&E is seeking an increase of $796 million over the currently authorized electric revenue requirement in that case. PG&E cites safety and reliability related reasons for its requested increase including the need for investments in its electric distribution system, and expenditures on its nuclear and hydroelectric facilities. The CPUC is expected to issue a decision in PG&E's 2014 GRC application in the 2nd quarter of 2014.

b) SCE 2015 GRC

In November 2013, SCE filed its 2015 GRC application. SCE is seeking an increase of $206 million over the currently authorized electric revenue requirement in that case. SCE cites the need to connect new customers to the system, upgrade its distribution infrastructure and business systems, test and replace distribution poles, and the increase in cost for removing depreciated assets as reasons for the increase it has requested. The CPUC is expected to issue a decision in SCE's 2015 GRC in late 2014 or early 2015.

c) SDG&E 2016 GRC

In the 4th quarter of 2014, SDG&E will file its 2016 GRC application. The CPUC will consider testimony and conduct hearings in that case during 2015. A decision is expected in late 2015 or early 2016.

2. Electric Fuel and Purchased Power Costs

The CPUC establishes PG&E's, SCE's, and SDG&E's revenue requirements to recover their costs for fuel for their power plants and to procure electricity under purchased power contracts in the annual ERRA forecast proceeding. The CPUC establishes an ERRA rate component based on a forecast of the costs, which are passed through to customers without any mark-up or profit for the utility. Fuel and purchased power costs fluctuate with the market prices.

Utilities' actual fuel and purchased power costs, and the revenues they collect from customers to pay these costs, are tracked in a balancing account and addressed in a subsequent ERRA or related CPUC proceeding. In the event that the revenues exceed the costs, then the account balance (difference between costs and revenues) is returned to the customers. If the costs exceed the revenues then the costs are recovered from customers.

The CPUC also has rules in place to ensure that the revenue requirement collected by the utilities tracks closely with the CPUC's pre-specified market price benchmarks for gas and actual purchased power costs. If a utility's ERRA account balance exceeds 4% of its actual generation revenues in the prior year (i.e., the "trigger" level) and the balance is expected to exceed 5% of those revenues, the utility is generally required to file an expedited application to propose to amortize the balance in rates, resulting in a rate reduction. If the balance is expected to decline below the 4% trigger level within 120 days, the utility may inform the CPUC in an advice letter, but is not required to file an expedited application.

The utilities' current authorized annual revenue requirements to recover fuel and purchased power costs adopted in the CPUC's ERRA forecast proceedings are shown below.

Table II-3
Annual Electric Revenue Requirements for Fuel and Purchased Power Costs
($ Million)

PG&E	SCE	SDG&E
$5,109	$3,797	$1,094
Effective Jan. 2014	Effective Nov. 2013	Effective April 2014

a) PG&E's ERRA

In December 2013 the CPUC approved PG&E's fuel and purchased power revenue requirement for 2014 as shown above. In June 2014 PG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2015.

b) SCE's ERRA

In November 2013 the CPUC authorized SCE's to recover its 2013 fuel and purchased power expenses shown above. SCE filed its 2014 ERRA application in which it requests a fuel and purchased power revenue requirement of $5,412 million for 2014. A CPUC decision in that case is expected in the 2nd quarter of 2014. SCE is currently scheduled to file its ERRA application for 2015 fuel and purchased power costs in August 2014. SCE has requested to change the filing date of its ERRA forecast applications to May; the CPUC is considering SCE's request.

c) SDG&E's ERRA

SDG&E fuel and purchased power revenue requirement of $1,094 million includes that approved in its 2013 ERRA forecast proceeding ($945 million effective Dec 2013) plus an additional $149 million that the CPUC authorized effective April 2014 in SDG&E's 2013 ERRA trigger proceeding to recover an under-collection accrued in SDG&E's ERRA balancing account. In April 2014 SDG&E will file its ERRA application to request a fuel and purchased power revenue requirement for 2015.

The CPUC also reviews each utility's energy procurement operations and purchased power contract administration activities for a prior annual period in a separate annual ERRA compliance proceeding for each utility.

The CPUC also reviews each utility's energy procurement operations and purchased power contract administration activities for a prior annual period in a separate annual ERRA compliance proceeding for each utility.

3. Investigation of San Onofre Nuclear Generating Station Units 2 and 3

Units 2 and 3 at the San Onofre Nuclear Generating Station (SONGS) were shut down in January 2012 due to problems with new steam generators that were installed in 2010 (Unit 2) and 2011 (Unit 3). SCE owns about 78% of SONGS and operates the plant; SDG&E owns 20%, and the remaining share is owned by the City of Riverside. SCE manages SONGS and announced in June 2013 that it would permanently shut down SONGS.

In late 2012 the CPUC opened an investigation to consider removing the plant from SCE's and SDG&E's rate base and to review the steam generator replacement project costs. SCE is collecting more than $600 million in rates for owning and operating the plant. These costs as well as SDG&E's share of SONGS costs in rates will be reviewed by the CPUC for reasonableness in the CPUC's investigation and could be refunded to ratepayers. The CPUC has separated the SONGS investigation into phases: In Phase 1 the CPUC reviewed the 2012 expenditures for SONGS, with a decision expected in March or April 2014. A proposed decision of the administrative law judges in Phase 1 orders a refund of $94 million for 2012 SONGS related costs that were collected in rates. In Phase 2 the CPUC is considering reductions to rate base for SONGS, and in Phase 3 the CPUC will consider the reasonableness of the steam generator replacement program. CPUC decisions in Phases 2 and 3 are expected in the 3rd and 4th quarters of 2014, respectively.

4. Plans to Improve Efficacy in Ratemaking

The CPUC has committed to improving the efficacy of its rulemakings, particularly in the areas of safety and accountability. In the wake of the 2010 San Bruno tragedy, the CPUC is reexamining its ratemaking processes, focusing primarily on safety and risk management.

In PG&E's 2014 GRC the CPUC required that independent consultants hired by the Safety and Enforcement Division evaluate risk assessments, risk mitigation, programs and policies, as well as PG&E's corporate policies, goals, culture, and efforts being made to bolster system safety and security. These reports are part of the record in the GRC and will be addressed in the CPUC's decision in the case.

In November 2013 the CPUC opened a rulemaking to develop a risk-based decision-making framework to evaluate safety and reliability improvements in GRCs. A decision is expected in this rulemaking at the end of 2014 which will make modifications to the GRC rate case scheduling plan and process so that the CPUC can more effectively consider safety and reliability programs and their costs in GRCs.

EXHIBIT 3

2014
STATISTICAL
REPORT

Unaudited Supplement to the Financial Report

Sempra Energy®

Schedule of Coverage Ratios and Common Stock

Sempra Energy®

	Years ended December 31,		
	2014	2013	2012
Interest coverage ratios[1]			
Before income taxes	3.62	3.60	2.99
After income taxes	3.28	2.95	2.87
Market price of common stock			
High	$ 116.30	$ 93.00	$ 72.87
Low	$ 86.73	$ 70.61	$ 54.70
Close	$ 111.36	$ 89.76	$ 70.94
Dividends declared per common share	$ 2.64	$ 2.52	$ 2.40
Dividend yield on common stock (at December 31)	2.4%	2.8%	3.4%
Dividend payout ratio (diluted)	57.0%	62.8%	69.0%
Book value at December 31	$ 45.98	$ 45.03	$ 42.43
Return on common equity	10.4%	9.4%	8.6%
Ratio of market price to book value per share at December 31	2.42	1.99	1.67
Common shares outstanding at December 31 (millions)	246.3	244.5	242.4
Weighted average number of shares outstanding (diluted, in millions)	250.7	249.3	246.7
Average daily trading volume (shares)	1,116,535	1,057,314	1,260,286
Common shareholders at December 31 (estimate)	205,000	230,000	245,000

[1] *Excludes interest expense.*

PART II

EM 4. RESERVED

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Edison International Common Stock is traded on the New York Stock Exchange under the symbol "EIX."

Market information responding to Item 5 is included in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 18. Quarterly Financial Data." There are restrictions on the ability of Edison International's subsidiaries to transfer funds to Edison International that materially limit the ability of Edison International to pay cash dividends. Such restrictions are discussed in the MD&A under the heading "Edison International Parent and Other" and in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debit and Credit Agreements." The number of common stockholders of record of Edison International was 45,430 on February 24, 2011. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page of this report. The description of Edison International's equity compensation plans required by Item 201(d) of Regulation S-K is incorporated by reference to "Part III—Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" of this report.

Issuer Purchases of Securities

The following table contains information about all purchases of Edison International Common Stock made by or on behalf of Edison International in the fourth quarter of 2010.

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2010 to October 31, 2010	568,862	$ 35.84	—	—
November 1, 2010 to November 30, 2010	718,119	$ 37.37	—	—
December 1, 2010 to December 31, 2010	1,022,928	$ 38.64	—	—
Total	2,309,909	$ 37.55	—	—

1 The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's: (i) 401(k) Savings Plan; (ii) Dividend Reinvestment and Direct Stock Purchase Plan; and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were never registered in Edison International's name and none of the shares purchased were retired as a result of the transactions.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Edison International Common Stock is traded on the New York Stock Exchange under the symbol "EIX."

Market information responding to Item 5 is included in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 19. Quarterly Financial Data." There are restrictions on the ability of Edison International's subsidiaries to transfer funds to Edison International that materially limit the ability of Edison International to pay cash dividends. Such restrictions are discussed in the MD&A under the heading "Liquidity and Capital Resources—Edison International Parent and Other," "—SCE—Dividend Restrictions," and in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debit and Credit Agreements." The number of common stockholders of record of Edison International was 41,000 on February 22, 2013. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page of this report. The description of Edison International's equity compensation plans required by Item 201(d) of Regulation S-K is incorporated by reference to "Part III—Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" of this report.

Purchases of Equity Securities by Edison International and Affiliated Purchasers

The following table contains information about all purchases of Edison International Common Stock made by or on behalf of Edison International in the fourth quarter of 2012.

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2012 to October 31, 2012	284,676	$ 46.75	—	—
November 1, 2012 to November 30, 2012	273,974	45.90	—	—
December 1, 2012 to December 31, 2012	680,367	45.11	—	—
Total	1,239,017	45.66	—	—

1 The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's: (i) 401(k) Savings Plan; (ii) Dividend Reinvestment and Direct Stock Purchase Plan; and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were never registered in Edison International's name and none of the shares purchased were retired as a result of the transactions.

Purchases of Equity Securities by Southern California Edison Company and Affiliated Purchasers

Certain information responding to Item 5 with respect to frequency and amount of cash dividends is included in "Item 8. Notes to the Consolidated Financial Statements—Note 19. Quarterly Financial Data." As a result of the formation of a holding company described in Item 1 above, all of the issued and outstanding common stock of SCE is owned by Edison International and there is no market for such stock.

Item 201(d) of Regulation S-K, "Securities Authorized for Issuance under Equity Compensation Plans," is not applicable because SCE has no compensation plans under which equity securities of SCE are authorized for issuance.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Edison International Common Stock is traded on the New York Stock Exchange under the symbol "EIX."

Market information responding to Item 5 is included in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 19. Quarterly Financial Data." There are restrictions on the ability of Edison International's subsidiaries to transfer funds to Edison International that materially limit the ability of Edison International to pay cash dividends. Such restrictions are discussed in the MD&A under the heading "Liquidity and Capital Resources—Edison International Parent and Other," "—SCE—Dividend Restrictions," and in "Item 8. Edison International Notes to Consolidated Financial Statements—Note 5. Debt and Credit Agreements." The number of common stockholders of record of Edison International was 41,000 on February 21, 2014. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page of this report. The description of Edison International's equity compensation plans required by Item 201(d) of Regulation S-K is incorporated by reference to "Part III—Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" of this report.

Purchases of Equity Securities by Edison International and Affiliated Purchasers

The following table contains information about all purchases of Edison International Common Stock made by or on behalf of Edison International in the fourth quarter of 2013.

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2013 to October 31, 2013	153,894	$ 48.22	—	—
November 1, 2013 to November 30, 2013	478,303	47.72	—	—
December 1, 2013 to December 31, 2013	227,571	46.14	—	—
Total	859,768	47.39	—	—

The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's: (i) 401(k) Savings Plan; (ii) Dividend Reinvestment and Direct Stock Purchase Plan; and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were never registered in Edison International's name and none of the shares purchased were retired as a result of the transactions.

Purchases of Equity Securities by Southern California Edison Company and Affiliated Purchasers

Certain information responding to Item 5 with respect to frequency and amount of cash dividends is included in "Item 8. Notes to the Consolidated Financial Statements—Note 19. Quarterly Financial Data." As a result of the formation of a holding company described in Item 1 above, all of the issued and outstanding common stock of SCE is owned by Edison International and there is no market for such stock.

Item 201(d) of Regulation S-K, "Securities Authorized for Issuance under Equity Compensation Plans," is not applicable because SCE has no compensation plans under which equity securities of SCE are authorized for issuance.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information responding to this section will appear in the Joint Proxy Statement under the heading "Independent Registered Public Accounting Firm Fees," and is incorporated herein by this reference.

MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Edison International Common Stock is traded on the New York Stock Exchange under the symbol "EIX."

Market information responding to this section is included in "Notes to Consolidated Financial Statements—Note 18. Quarterly Financial Data (Unaudited)." There are restrictions on the ability of Edison International's subsidiaries to transfer funds to Edison International that materially limit the ability of Edison International to pay cash dividends. Such restrictions are discussed in the MD&A under the heading "Liquidity and Capital Resources—Edison International Parent and Other," and in "Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies—SCE Dividend Restrictions" and "—Note 5. Debt and Credit Agreements." The number of common stockholders of record of Edison International was 41,000 on February 21, 2014. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page of this report. Required information about Edison International's equity compensation plans is incorporated by reference to "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" of this report.

Purchases of Equity Securities by Edison International and Affiliated Purchasers

The following table contains information about all purchases of Edison International Common Stock made by or on behalf of Edison International in the fourth quarter of 2014.

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2014 to October 31, 2014	430,555	$ 60.17	—	—
November 1, 2014 to November 30, 2014	305,807	62.70	—	—
December 1, 2014 to December 31, 2014	621,358	65.35	—	—
Total	1,357,720	63.11	—	—

[1] The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's: (i) 401(k) Savings Plan; (ii) Dividend Reinvestment and Direct Stock Purchase Plan; and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were never registered in Edison International's name and none of the shares purchased were retired as a result of the transactions.

Purchases of Equity Securities by Southern California Edison and Affiliated Purchasers

Information with respect to frequency and amount of cash dividends is included in "Notes to the Consolidated Financial Statements—Note 18. Quarterly Financial Data (Unaudited)." As a result of the formation of a holding company described under the heading "Business" above, all of the issued and outstanding common stock of SCE is owned by Edison International and there is no market for such stock.

Information on securities authorized for issuance under equity compensation plans, is not applicable because SCE has no compensation plans under which equity securities of SCE are authorized for issuance.

DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning executive officers of Edison International is set forth above under "Executive Officers of Edison International." Other information responding to this section will appear in Edison International's and SCE's definitive Proxy Statement under the headings "Item 1: Election of Directors," and is incorporated herein by this reference.

The Edison International Employee Code of Conduct is applicable to all officers and employees of Edison International and its subsidiaries. The Code is available on Edison International's Internet website at www.edisoninvestor.com at "Corporate Governance." Any amendments or waivers of Code provisions for the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, will be posted on Edison International's Internet website at www.edisoninvestor.com.

In December 2015, the Edison International Board of Directors adopted revisions to the Edison International Bylaws that provided shareholders with proxy access for director elections at annual meetings. The Bylaws provide that Edison International will include in its Proxy Statement up to two nominees (or nominees for up to 20% of the Edison International Board, whichever is greater) submitted by a shareholder or group of up to 20 shareholders owning at least 3% of the Edison International common stock continuously for at least three years, if the shareholder group and nominee satisfy the requirements of the Edison International Bylaws.

EXECUTIVE COMPENSATION

Information responding to this section will appear in the Joint Proxy Statement under the headings "Compensation Discussion and Analysis," "Compensation Committee Interlocks and Insider Participation," "Executive Compensation" "Director Compensation" and "Compensation Committee Report," and is incorporated herein by this reference.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information responding to this section will appear in the Joint Proxy Statement under the heading "Our Stock Ownership," and is incorporated herein by this reference.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information responding to this section will appear in the Joint Proxy Statement under the headings "Certain Relationships and Related Transactions," and "Our Corporate Governance—Is SCE subject to the same corporate governance stock exchange rules as EIX?", "—How does the Board determine which directors are independent?", "—Which directors has the Board determined are independent to serve on the Board?" and "Where can I find the Company's corporate governance documents?" and is incorporated herein by this reference.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information responding to this section will appear in the Joint Proxy Statement under the heading "Independent Auditor Fees," and is incorporated herein by this reference.

MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Edison International Common Stock is traded on the New York Stock Exchange under the symbol "EIX."

Market information responding to this section is included in "Notes to Consolidated Financial Statements—Note 18. Quarterly Financial Data (Unaudited)." There are restrictions on the ability of Edison International's subsidiaries to transfer funds to Edison International that materially limit the ability of Edison International to pay cash dividends. Such restrictions are discussed in the MD&A under the heading "Liquidity and Capital Resources—Edison International Parent and Other," and in "Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies—SCE Dividend Restrictions." The number of common stockholders of record of Edison International was 35,375 on February 19, 2016. Additional information concerning the market for Edison International's Common Stock is set forth on the cover page of this report. Required information about Edison International's equity compensation plans will appear in the Joint Proxy Statement under the heading "Item 4: Approval of an Amendment to the EIX 2007 Performance Incentive Plan," and is incorporated herein by this reference.

"me	Position	Period Held Office
.yar B. Mistry	Vice President, Chief Financial Officer, and Controller	October 1, 2011 to present
	Vice President and Controller, PG&E Corporation	March 8, 2010 to present
	Vice President and Controller	March 8, 2010 to September 30, 2011
	Vice President and Chief Risk and Audit Officer	September 16, 2009 to March 7, 2010
	Vice President and Chief Risk and Audit Officer, PG&E Corporation	August 1, 2009 to March 7, 2010
	Vice President, Internal Auditing/Compliance and Ethics, PG&E Corporation	January 1, 2009 to July 31, 2009
	Vice President, Regulation and Rates	September 20, 2007 to December 31, 2008
	Vice President, State Regulation	November 9, 2005 to September 19, 2007

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

As of February 7, 2012, there were 71,943 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss stock exchanges. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2011 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report. Shares of common stock of the Utility are not listed but are solely owned by PG&E Corporation. Information about the frequency, amount, and restrictions upon the payment of, dividends on common stock declared by PG&E Corporation and the Utility appears in the 2011 Annual Report in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, in Note 6: Common Stock and Share-based Compensation–Dividends, of the Notes to the Consolidated Financial Statements, and in the section of MD&A entitled "Liquidity and Financial Resources—Dividends," which information is incorporated by reference and included in Exhibit 13 to this report.

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2011, PG&E Corporation made equity contributions totaling $205 million to the Utility in order to maintain the Utility's 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2011.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2011, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the fourth quarter of 2011, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

Item 6. *Selected Financial Data*

A summary of selected financial information, for each of PG&E Corporation and the Utility for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2011 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

A discussion of PG&E Corporation's and the Utility's consolidated financial condition and results of operations is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2011 Annual Report, which discussion is incorporated by reference and included in Exhibit 13 to this report.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

As of February 11, 2013, there were 67,982 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss stock exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2012 Annual Report, which information is incorporated herein by reference. Shares of common stock of the Utility are solely owned by PG&E Corporation. Information about the frequency, amount, and restrictions upon the payment of, dividends on common stock declared by PG&E Corporation and the Utility is set forth in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, Note 6: Common Stock and Share-Based Compensation–Dividends of the Notes to the Consolidated Financial Statements, and within MD&A under the heading "Liquidity and Financial Resources—Dividends," in the 2012 Annual Report, which information is incorporated herein by reference.

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2012, PG&E Corporation made equity contributions totaling $170 million to the Utility in order to maintain the Utility's 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2012.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
October 1 through October 31, 2012	-	-	-	$ -
November 1 through November 30, 2012	-	-	-	-
December 1 through December 31, 2012	406 [1]	$39.71	-	-
Total	406	$39.71	-	$ -

[1] Shares of PG&E Corporation common stock tendered to pay stock option exercise price.

During the quarter ended December 31, 2012, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

Item 6. ***Selected Financial Data***

Selected financial information, for each of PG&E Corporation and the Utility for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2012 Annual Report, which information is incorporated herein by reference.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

A discussion of PG&E Corporation's and the Utility's consolidated financial condition and results of operations is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2012 Annual Report, which discussion is incorporated herein by reference.

ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

As of February 3, 2014, there were 64,972 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss stock exchange. The high and low sales prices of PG&E Corporation common stock for each qu of the two most recent fiscal years are set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2013 Annual Report, which information is incorporated herein by reference. Shares of common stock of the Utility are solely owned by PG&E Corporation. Information about the frequency, amount, and restrictions upon the payment of, dividends on common stock declared by PG&E Corporation and the Utility is set forth in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, Note 5: Common Stock and Share-Based Compensation–Dividends of the Notes to the Consolidated Financial Statements, and within MD&A under the heading "Liquidity and Financial Resources—Dividends," in the 2013 Annual Report, which information is incorporated herein by reference.

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2013, PG&E Corporation made equity contributions totaling $305 million to the Utility in order to maintain the Utility's 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2013.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2013, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2013, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. Selected Financial Data

Selected financial information, for each of PG&E Corporation and the Utility for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

A discussion of PG&E Corporation's and the Utility's consolidated financial condition and results of operations is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Re of Operations" as well as the "Glossary" in the 2013 Annual Report, which discussion is incorporated herein by reference.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A is set forth within MD&A under the heading "Risk Management Activities," and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

ITE M 8. Financial Statements and Supplementary Data

Information responding to Item 8 is set forth under the following headings for PG&E Corporation: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity;" under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity" in the 2013 Annual Report and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," and "Reports of Independent Registered Public Accounting Firm" in the 2013 Annual Report, which information is incorporated herein by reference.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of January 27, 2015, there were 61,989 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth on page 128 of this report within "Quarterly Consolidated Financial Data (Unaudited)"in Item 8. Shares of common stock of the Utility are wholly owned by PG&E Corporation. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock Utility appears in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5: Common Stock and Share-Based Compensation – Dividends in Item 8 and in "Liquidity and Financial Resources – Dividends" in Item 7. MD&A.

Sales of Unregistered Equity Securities

PG&E Corporation did not make any equity contributions to the Utility during the quarter ended December 31, 2014. The Utility was in compliance with the 52% common equity component of its capital structure authorized by the CPUC and had adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2014.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2014, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2014, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of February 12, 2016, there were 59,317 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange. The high and low sales prices of PG&E Corporation common stock for each quarter of the two most recent fiscal years are set forth in the table entitled "Quarterly Consolidated Financial Data (Unaudited)" which appears after the Notes to the Consolidated Financial Statements in Item 8. Shares of common stock of the Utility are wholly owned by PG&E Corporation. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock Utility appears in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 of the Notes to the Consolidated Financial Statements in Item 8 and in "Liquidity and Financial Resources – Dividends" in Item 7 below.

Sales of Unregistered Equity Securities

PG&E Corporation made equity contributions to the Utility totaling $100 million during the quarter ended December 31, 2015. PG&E Corporation did not make any sales of unregistered equity securities during 2015 in reliance on an exemption from registration under the Securities Act of 1933, as amended. However, PG&E Corporation recently discovered, based on a review of new accounts opened under its Dividend Reinvestment and Stock Purchase Plan ("DRSPP") since 2013, that it issued and sold shares of common stock under the optional cash purchase feature of its DRSPP more than three years after the related registration statement for the DRSPP became effective, including approximately 19,550 shares for estimated aggregate sales proceeds of $1 million during the year ended December 31, 2015. As a result, participants who purchased these shares may have a rescission right that would allow them to return the shares to PG&E Corporation in exchange for the purchase price paid by such participants, plus interest, less the value of dividends received.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2015, PG&E Corporation did not redeem or repurchase any shares of common .tock outstanding. Also, during the quarter ended December 31, 2015, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

EXHIBIT 4

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number	Exact Name of Registrant as specified in its charter	State or Other Jurisdiction of Incorporation or Organization	IRS Employer Identification Number
1-9936	EDISON INTERNATIONAL	California	95-4137452
1-2313	SOUTHERN CALIFORNIA EDISON COMPANY	California	95-1240335

EDISON INTERNATIONAL	SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue	2244 Walnut Grove Avenue
(P.O. Box 976)	(P.O. Box 800)
Rosemead, California 91770	Rosemead, California 91770
(Address of principal executive offices)	(Address of principal executive offices)
(626) 302-2222	(626) 302-1212
(Registrant's telephone number, including area code)	(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Edison International: Common Stock, no par value	NYSE LLC
Southern California Edison Company: Cumulative Preferred Stock 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series	NYSE MKT LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Edison International Yes ☑ No ☐ Southern California Edison Company Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
Edison International Yes ☐ No ☑ Southern California Edison Company Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Edison International Yes ☑ No ☐ Southern California Edison Company Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Edison International Yes ☑ No ☐ Southern California Edison Company Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
Edison International ☑ Southern California Edison Company ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "accelerated filer," "large accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check One):

Edison International	Large Accelerated Filer ☑	Accelerated Filer ☐	Non-accelerated Filer ☐	Smaller Reporting Company ☐
Southern California Edison Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☑	Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Edison International Yes ☐ No ☑ Southern California Edison Company Yes ☐ No ☑

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2015, the last business day of the most recently completed second fiscal quarter:
Edison International Approximately $18.1 billion Southern California Edison Company Wholly owned by Edison International

Common Stock outstanding as of February 19, 2016:

Edison International	325,811,206 shares
Southern California Edison Company	434,888,104 shares (wholly owned by Edison International)

DOCUMENTS INCORPORATED BY REFERENCE

Designated portions of the Proxy Statement relating to registrants' joint 2016 Annual Meeting of Shareholders have been incorporated by reference into the parts of this report where indicated.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2015

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ________ to __________

Commission File Number	Exact Name of Registrant as Specified In Its Charter	State or Other Jurisdiction of Incorporation or Organization	IRS Employer Identification Number
1-12609	PG&E CORPORATION	California	94-3234914
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	California	94-0742640

PG&E Corporation.
77 Beale Street, P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 973-1000
(Registrant's telephone number, including area code)

Pacific Gas and Electric Company*
77 Beale Street, P.O. Box 770000
San Francisco, California 94177
(Address of principal executive offices) (Zip Code)
(415) 973-7000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
PG&E Corporation: Common Stock, no par value	New York Stock Exchange
Pacific Gas and Electric Company: First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5%	NYSE Amex Equities

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

PG&E Corporation	Yes ☑ No ☐
Pacific Gas and Electric Company	Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

PG&E Corporation	Yes ☐ No ☑
Pacific Gas and Electric Company	Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PG&E Corporation	Yes ☑ No ☐
Pacific Gas and Electric Company	Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PG&E Corporation	Yes ☑ No ☐
Pacific Gas and Electric Company	Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

PG&E Corporation	☑
Pacific Gas and Electric Company	☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

PG&E Corporation	**Pacific Gas and Electric Company**
Large accelerated filer ☑	Large accelerated filer ☐
Accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☐	Non-accelerated filer ☑
Smaller reporting company ☐	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

PG&E Corporation	Yes ☐ No ☑
Pacific Gas and Electric Company	Yes ☐ No ☑

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2015, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$23,628 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 12, 2016:

PG&E Corporation:	492,830,471 shares
Pacific Gas and Electric Company:	264,374,809 shares (wholly owned by PG&E Corporation)

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

Designated portions of the Joint Proxy Statement relating to the 2016 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission File No.	Exact Name of Registrants as Specified in their Charters, Address and Telephone Number	State of Incorporation	I.R.S. Employer Identification Nos.
1-14201	SEMPRA ENERGY 488 8th Avenue San Diego, California 92101 (619)696-2000	California	33-0732627
1-03779	SAN DIEGO GAS & ELECTRIC COMPANY 8326 Century Park Court San Diego, California 92123 (619)696-2000	California	95-1184800
1-01402	SOUTHERN CALIFORNIA GAS COMPANY 555 West Fifth Street Los Angeles, California 90013 (213)244-1200	California	95-1240705

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Each Exchange on Which Registered
Sempra Energy Common Stock, without par value	NYSE

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Southern California Gas Company Preferred Stock, $25 par value
6% Series A, 6% Series

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

	Yes		No	
Sempra Energy	Yes	X	No	
San Diego Gas & Electric Company	Yes		No	X
Southern California Gas Company	Yes		No	X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

	Yes		No	
Sempra Energy	Yes		No	X
San Diego Gas & Electric Company	Yes		No	X
Southern California Gas Company	Yes		No	X

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X No ____

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Sempra Energy	Yes	X	No	
San Diego Gas & Electric Company	Yes	X	No	
Southern California Gas Company	Yes	X	No	

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Sempra Energy	X
San Diego Gas & Electric Company	X
Southern California Gas Company	X

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
Sempra Energy	[X]	[ ]	[ ]	[ ]
San Diego Gas & Electric Company	[ ]	[ ]	[X]	[ ]
Southern California Gas Company	[ ]	[ ]	[X]	[ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Sempra Energy	Yes		No	X
San Diego Gas & Electric Company	Yes		No	X
Southern California Gas Company	Yes		No	X

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2015:

Sempra Energy	$24.5 billion (based on the price at which the common equity was last sold as of the last business day of the most recently completed second fiscal quarter)
San Diego Gas & Electric Company	$0
Southern California Gas Company	$0

Common Stock outstanding, without par value, as of February 19, 2016:

Sempra Energy	249,215,763 shares
San Diego Gas & Electric Company	Wholly owned by Enova Corporation, which is wholly owned by Sempra Energy
Southern California Gas Company	Wholly owned by Pacific Enterprises, which is wholly owned by Sempra Energy

EXHIBIT 2

Michael J. Aguirre, Esq., SBN 060402
Maria C. Severson, Esq., SBN 173967
AGUIRRE & SEVERSON, LLP
501 West Broadway, Suite 1050
San Diego, CA 92101
Telephone: (619) 876-5364
Facsimile: (619) 876-5368

Attorneys for Petitioner

SUPERIOR COURT OF THE STATE OF CALIFORNIA

COUNTY OF IMPERIAL

IMPERIAL IRRIGATION DISTRICT, Petitioner, v. CALIFORNIA INDEPENDENT SYSTEM OPERATOR and DOES 1-20, inclusive, Respondents.	Case No. ECU08934 **DECLARATION OF MICHAEL J. AGUIRRE IN SUPPORT OF PETITIONER'S RESPONSE IN OPPOSITION TO CAISO'S MOTION TO TRANSFER VENUE** Date: January 20, 2016 Time: 8:30 a.m. Dept. 7 Judge: Hon. Jeffrey B. Jones Complaint filed: October 9, 2015

I, Michael J. Aguirre, hereby declare as follows:

1. I am an attorney duly licensed to practice law before all of the courts of the State of California, and I am a partner with the law firm of Aguirre & Severson LLP, one of the attorneys of record for the Plaintiffs/Cross-Defendants in this action. Except where otherwise stated, I have personal knowledge of the matters stated herein and if sworn as a witness could and would testify competently thereto.

2. Exhibit 1 is a true and correct copy of a letter received by me from the ISO describing a CD.

3. Exhibit 2 is a true and correct copy of pages from the Imperial Irrigation District's 2014 Annual Report the Cover page, Contents page, and pages 16-17.

4. Exhibit 3 is a true and correct copy of a 27 February 2014 email from ISO's Kelly Kristen to ISO External Affairs Manager Gregory Van Pelt, CPUC Commissioner Michael Picker, CPUC Energy Department head Ed Randolph, ISO Policy VP Karen Edson, and several other CEC and CPUC officials detailing what the group had decided or was considering for decision.

5. Attached as Exhibit 4 is a true and correct copy of the 1 February 2012 Edison Event Notification to NRC.

6. Attached as Exhibit 5 is a true and correct copy of the Energy Institute at HAAS Work Paper 248 Market Impacts of A Nuclear Power Plant Closure (Revised 2015), cover page and page 1.

7. Attached as Exhibit 6 is a true and correct copy of a 5 April 2012 California Public Utilities Commission (CPUC) email to 25 recipients notes of the private meeting with SCE Gary Schoonyan regarding "SONGS summer planning meeting with SCE."

8. http://www.eenews.net/videos/1514 is a website that includes a video of ISO head Steve Berberich. Attached as Exhibit 7 is a true and correct copy of the 18 April 2012website link page.

9. Attached as Exhibit 8 is a true and correct copy of the 7 May 2012 California Energy Commission (CEC) 2012 Summer Readiness presentation by Robert Weisenmiller, Chair

of the California Energy Commission, Paul Clanon, Executive Director of the California Public Utilities Commission, and Steve Berberich, Chief Executive Officer of the California Independent System Operator.

10. Attached as Exhibit 9 is a true and correct copy of a 13 October 2012 email from Edison President Litzinger to CPUC President Peevey.

11. Attached as Exhibit 10 is a true and correct copy of a 12 June 2013 email from ISO's CEO, Berberich, to regulators and utility executives describing the mission of the "loss of SONGS" Task Force.

12. Attached hereto as Exhibit 11 is a true and correct copy of an 11 August 2014 email the CPUC's Michael Picker to Karen Edson ISO Vice President, Policy regarding Imperial geothermal as a baseload source of energy.

13. Attached hereto as Exhibit 12 is a true and correct copy of a memorandum written for the 8 July 2013 SO replacement power meeting provided: "President Peevey has reserved a private room on the 3rd floor of the California Club** Time: 6:00-9:00pm (6:00 Drinks 6:30 pm Dinner)" and Meeting Calendar for 8 July 2013 SONGS strategy dinner, Memorandum post SONGS Strategy Dinner at the California Club located at 538 S. Flower in downtown Los Angeles in a private dining room on the club's third floor.

14. Attached hereto as Exhibit 13 is a true and correct copy of an 8 August 2014 (4:09 PM) email from ISO Director of State Government Affairs, Mary McDonald, to Governor Brown's Deputy Legislative Secretary, Martha Guzman-Aceves, regarding IID's efforts to increase transportation of its geothermal, solar and other renewable energy sources through the ISO to energy supply markets; and an email sent thirteen minutes later from ISO's Vice President for Policy and Client Services, Karen Edson, forwarding Ms. McDonald's email to CPUC Commissioner Michael Picker (previously on the Governor's renewable energy staff) accusing IID General Manager, Kevin Kelley, of making "incorrect representations to the Legislature."

15. Attached hereto as Exhibit 14 is a true and correct copy of an email invite from CEC Chairman Robert Weisenmiller regarding a 17 June 2014 meeting at the home of Air

Resources Board Chair, Mary Nichols to CEC Executive Director Rob Oglesby, CEC Commissioner Janea Scott, CEC Chair Bob Weisenmiller, ISO President Steve Berberich, CPUC Commissioners Peevey and Picker, and Senior Adviser to Governor Brown, Cliff Rechtschaffen.

16. Attached hereto as Exhibit 15 is a 14 December 2013 dinner meeting at the California Club calendar item between CPUC officials (e.g. Michael Peevey) and long-time Edison CEO Al Fohrer (2002-2010) and Edison Attorney Steven Pickett.

17. Attached as Exhibit 16 is a 27 April 2015 and September 2015 series of emails between ISO and agents, officers, and employees of PacifiCorp, a utility corporation operating in six Western states that were part of emails obtained by my office from the Oregon Public Utility Commission (OPUC).

18. Attached as Exhibit 16 is the cover page of SB 350 was approved by the legislature on Friday, 11 September 2015.

I declare under penalty of perjury under the laws of the state of California that the foregoing is true and correct.

Executed this 5th day of January 2016, at San Diego, CA.

Michael J. Aguirre, Esq.

EXHIBIT 1

California ISO

California Independent System Operator Corporation

RECEIVED
AUG 31 2015
By Fed Ex

August 27, 2015

Via Electronic Mail & FedEx

Michael J. Aguirre, Esq.
Maria C. Severson, Esq.
Aguirre & Severson, LLP
501 West Broadway, Suite 1050
San Diego, CA 92101

Re: Imperial Irrigation District Public Records Requests

Dear Mr. Aguirre and Ms. Severson:

This letter responds to 37 overlapping records requests that you have sent to the California Independent System Operator Corporation ("ISO") and various ISO personnel on behalf of your client Imperial Irrigation District ("IID") over the course of the last several weeks.

In summary, we have collected and enclosed with this letter a CD containing more than 17,000 pages of publicly available materials that are responsive to your various requests and have identified additional materials that we would be able to provide, if your client authorizes you to enter into a suitable non-disclosure agreement on its behalf covering security-sensitive information contained within those materials. We also respond specifically to two of your requests below. This transmittal does not provide individualized responses to the remainder of your requests, and we must deny them, because as discussed below, they are vague and overbroad, seeking voluminous material on numerous open-ended topics over multiple years. As we noted previously, we remain available to work with you in an effort to identify a more particularized and focused set of requests consistent with our Records Availability Policy ("RAP").

This letter is the ISO's initial written response under the RAP to 35 of the 37 requests we have received from your office, which we believe are all of your outstanding requests.[1] We responded to your first two requests in a July 17 letter, and in response

[1] We are uncertain whether these constitute all of your requests. In many instances, the requests were sent to individual ISO personnel or invalid e-mail addresses, rather than to the ISO records mailbox as required by the RAP. Although we are responding

to that letter, you called, and we conferred on August 11 and 12. We also briefly discussed at that time the numerous additional requests the ISO had by then received from your office. I advised you that the ISO would provide a written response regarding these additional requests within approximately 14 days. On August 12, I sent you a letter confirming this understanding.

The ISO's RAP requires a party seeking records to make a request that is "sufficiently clear to reasonably describe an identifiable record." This requirement is important because it creates a starting point for the ISO to search for, collect, and review potentially responsive materials to determine whether they may be produced consistent with the ISO's confidentiality obligations, which include keeping various categories of information confidential, such as:[2]

- "Critical energy infrastructure information" that must be protected to safeguard the security of the electric system;
- "Commercially sensitive" information which could negatively impact competition among ISO customers or efficient operations;
- Proprietary data belonging to third parties;
- Certain preliminary drafts, notes, and memoranda; and
- Other materials that the ISO is required to keep confidential under its tariff or other regulatory requirements, including those imposed by the Federal Energy Regulatory Commission, federal or state law.

With two exceptions discussed below, your requests collectively and individually seek information contained within each of these protected categories. In addition, the requests are not "sufficiently clear" nor "reasonably describe" an identifiable record, and are thus not tailored or framed in a manner that enables the ISO to search for, collect, and review the vast volume of materials implicated, to determine which materials may be disclosable and which may not. The requests generally seek all documents in any form within a series of broadly defined, vaguely worded, and overlapping categories that in most cases span multiple years. There are, for example, multiple requests seeking all "real time flow data" across various transmission facilities for multiple years, numerous requests seeking all communications "mentioning" or "relating to" various aspects of the ISO's transmission planning or related topics over more than four years, and multiple requests seeking "all documents and writings" over a three-year period "relating" in any manner to various transmission upgrade projects. Responding to such requests is not feasible because it would require the ISO to search a massive amount of

---

to all known requests, many were not properly submitted under the RAP, and we reserve our right to object to any requests not properly submitted.

[2] See, the Records Availability Policy, Section 5.2.

data and records, and then analyze each page of each record to determine whether it is disclosable, protected under the RAP, or may be publicly disseminated.

Although these requests do not meet the "identifiable record" requirement, the ISO has nonetheless undertaken a substantial effort to identify and collect publicly available records from our annual transmission planning and related stakeholder processes that are responsive to many of your requests. These records total more than 17,000 pages. We copied them onto a CD that is enclosed with this letter for your convenience. The ISO has also located additional related materials from our annual transmission planning stakeholder and related processes that include security-sensitive critical energy infrastructure information. Our existing policies make these materials available to market participants and certain other stakeholders, including IID, provided that they enter into an appropriate non-disclosure agreement protecting against misuse of the information or disclosure to other parties. We are willing to explore whether, with your client's permission and consent, it would be possible to enter into a suitable non-disclosure agreement with you that would allow us to provide those additional materials to you.

As noted, two of your requests, while not properly submitted under the RAP, are sufficiently clear and particular to permit an individualized response. Specifically, on July 21 you sent two requests to the ISO CEO seeking any records reflecting any ownership interests that ISO leadership may have in Southern California Edison, Pacific Gas & Electric, Berkshire Hathaway, and Sempra, or reporting any financial interest by ISO leadership in a related party transaction. The ISO responds that no such documents exist. ISO leadership does not hold any interests in the identified entities, nor have they engaged in any related party transactions.

We continue to remain willing to work with you to identify and provide additional publicly available records consistent with our RAP. Please do not hesitate to contact me if you would like to discuss this matter further.

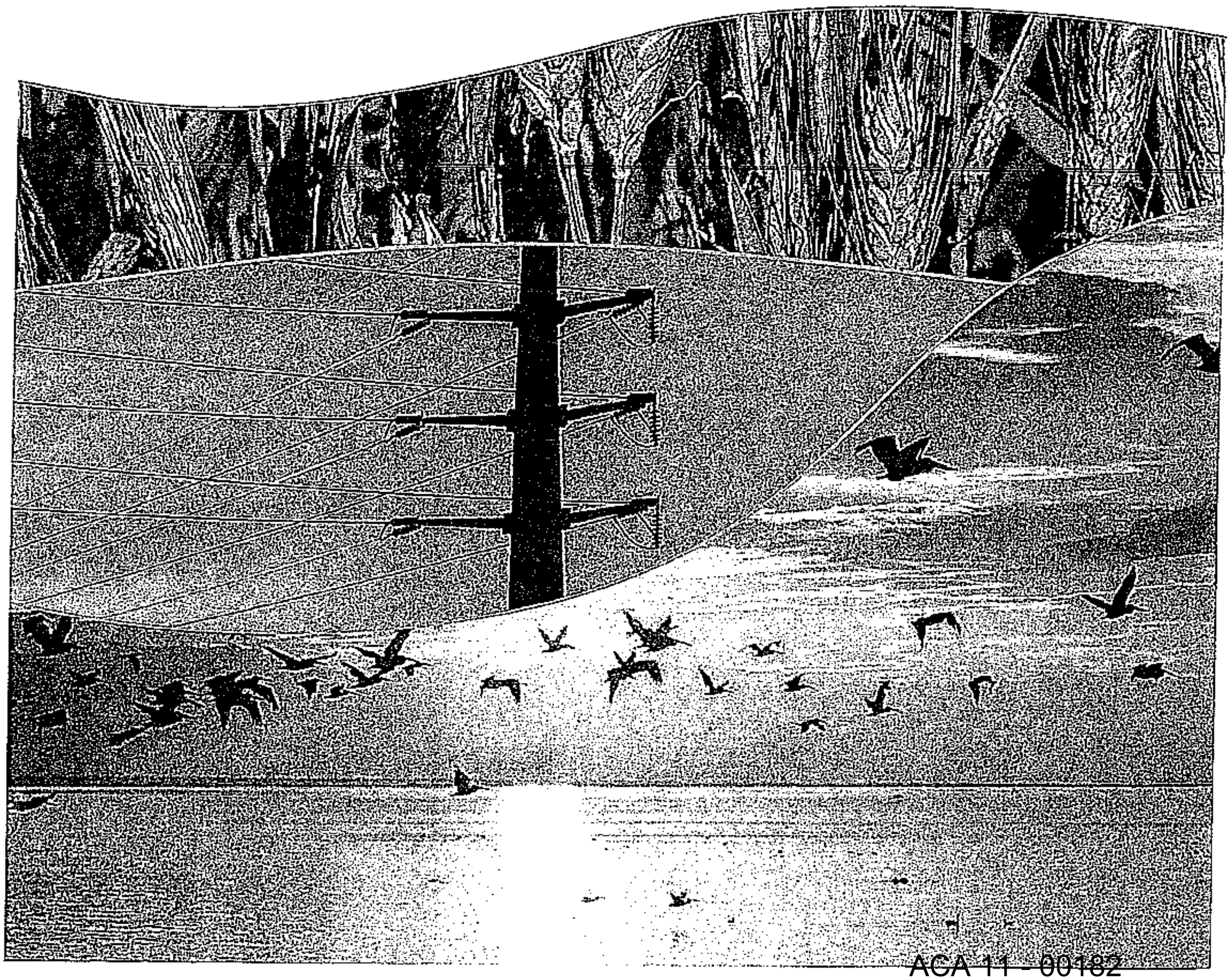
Very truly yours,

John Spomer
Senior Counsel

Enclosure (via FedEx)

EXHIBIT 2

IMPERIAL IRRIGATION DISTRICT • ANNUAL REPORT



ACA 11 - 00182

CONTENTS

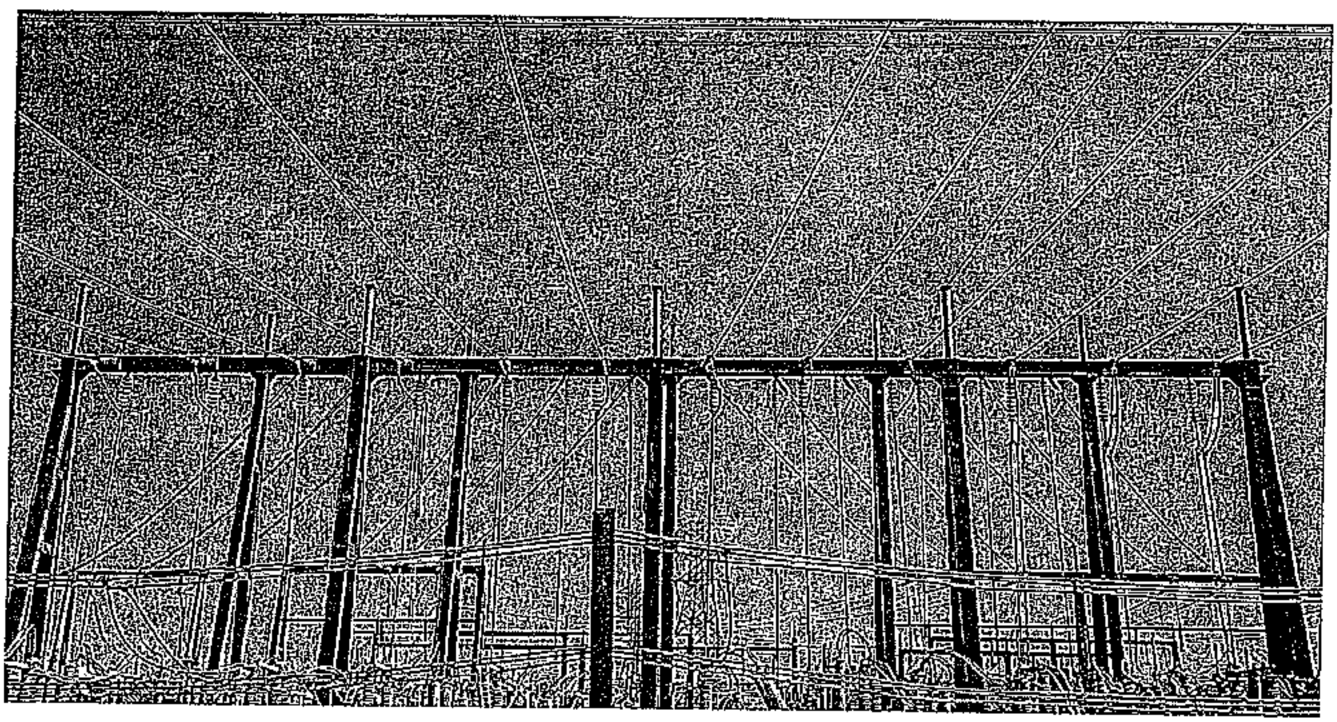
Transmission

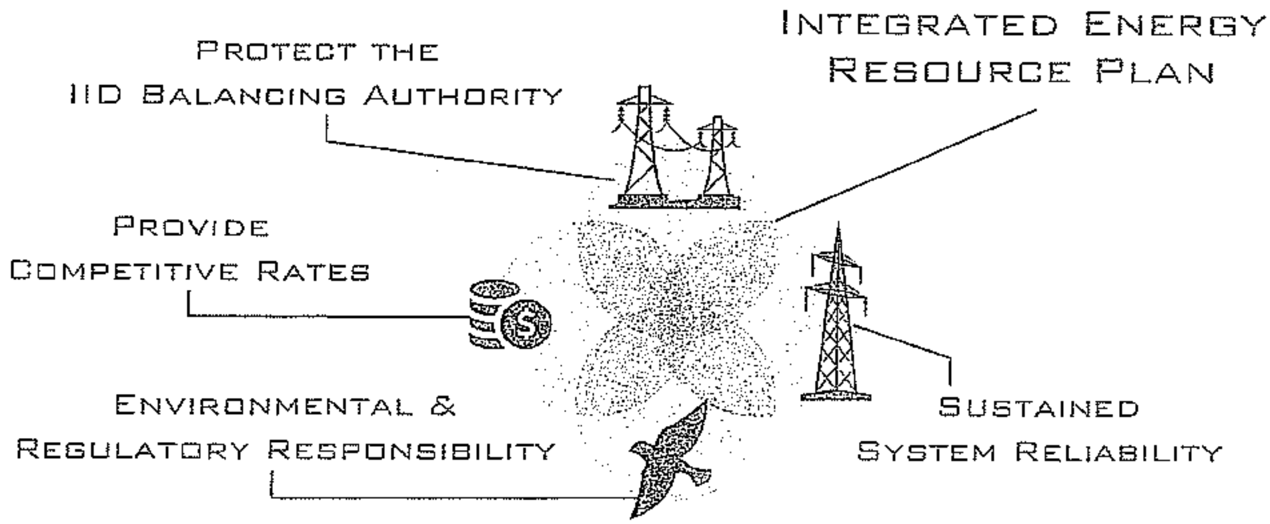
IID continues to strengthen its infrastructure so renewable energy can be carried through its transmission system into the regional grid. The district's multiregional Strategic Transmission Expansion Plan expands the export capability of renewables to the grid while ensuring that IID maintains its balancing authority, meets federal and state regulations and replaces lost generation in California.

The plan proposes the construction of a 2,200-megawatt, 230-kilovolt collector system in the IID service territory. The district proposes to finance, construct and upgrade its internal transmission network, creating an internal collector system that would facilitate the export of 1,100 megawatts to the state and simultaneously another 1,100 megawatts to the greater desert Southwest. IID would be able to further enhance the system as the need for additional renewable energy generation occurs.

IID also completed Path 42 in 2014, rebuilding the Coachella Valley-Ramon transmission line in an attempt to address the most restrictive element in transmitting renewables in energy-rich Southern California. The upgrade increases transmission capacity and reduces congestion, enabling the efficient flow of green energy to and from IID's service area.

The district is also working with Arizona Public Service to explore joint participation in an energy transmission line between Yuma and Phoenix to accommodate generation, interconnection and grid reliability.





Integrating resources

IID ramped up its integrated energy resource plan in 2014 to support growing needs, intending to invest $1 billion in local energy capital projects over the next five years. Projects range from a state-of-the-art battery storage system in El Centro and the purchase of a solar plant in Niland to an aggressive systematic upgrade of the transmission system.

To help fund this ambitious work, following a comprehensive cost-of-service study and public hearings, an increase was approved to IID's base electric service rate (about 7 percent). Effective in 2015, the goal of the first rate increase in 20 years is to create a balance of rate structures that will provide reasonable revenue stability.

Developing a 20-megawatt, 33-megavolt ampere utility-grade battery storage system is one major project in integrating IID's energy resources. In 2014, the district completed engineering studies for the battery storage system, which is designed to provide operational support across IID's balancing authority through rapid response support capabilities that mitigate stability and power quality issues when energy from renewable sources are integrated into the local grid. Since the use of battery storage on a utility scale is relatively new to the energy industry, IID is on the cutting edge and leading the way.

As a local public energy provider not governed by shareholders, many of IID's changes are driven by its intent to maintain its balancing authority in a changing regulatory environment and continuing to provide reliable, low-cost electric service to the public that it serves.

EXHIBIT 3

Message

From:	Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
Sent:	2/28/2014 3:21:29 PM
To:	Picker, Michael [Michael.Picker@cpuc.ca.gov]
Subject:	Re: updated DRAFT for our meeting today

Looks good. I am pushing for a dinner of task force leads in April. Also another joint iepr workshop in the summer to review status

Bob
Sent from my iPhone

> On Feb 28, 2014, at 5:12 AM, "Picker, Michael" <Michael.Picker@cpuc.ca.gov> wrote:
>
> FYI.
>
> Michael Picker
> Redacted
>
> Begin forwarded message:
>
> From: Michael Picker <Michael.Picker@GOV.CA.GOV<mailto:Michael.Picker@GOV.CA.GOV>>
> Date: February 27, 2014 7:28:08 PM PST
> To: "Michael Picker (michael.picker@cpuc.ca.gov<mailto:michael.picker@cpuc.ca.gov>)" <michael.picker@cpuc.ca.gov<mailto:michael.picker@cpuc.ca.gov>>
> Subject: FW: updated DRAFT for our meeting today
>
> Michael Picker,
> formerly Senior Advisor to the Governor for Renewable Energy Facilities
>
> FYI: my new contacts are
>
> Commissioner Michael Picker
> California Public Utilities Commission
> 505 Van Ness Street, Fifth Floor
> San Francisco, CA 94102
> (415) 703-2444
>
> From: Kelley, Kristen [mailto:kkelley@caiso.com]
> Sent: Thursday, February 27, 2014 1:16 PM
> To: Van Pelt, Gregory; Michael Picker; Randolph, Edward; 'Tollstrup, Michael@ARB (mtollstr@arb.ca.gov<mailto:mtollstr@arb.ca.gov>)'; Pettingill, Phil; 'Drew.Bohan@energy.ca.gov<mailto:Drew.Bohan@energy.ca.gov>'; ''Kasmar, Jeff' (Jeff.Kasmar@cpuc.ca.gov<mailto:Jeff.Kasmar@cpuc.ca.gov>)'; 'Oglesby, Rob@Energy (Rob.Oglesby@energy.ca.gov<mailto:Rob.Oglesby@energy.ca.gov>)'; 'Barker, Kevin@Energy (Kevin.Barker@energy.ca.gov<mailto:Kevin.Barker@energy.ca.gov>)'; 'Walker, Cynthia (cynthia.walker@cpuc.ca.gov<mailto:cynthia.walker@cpuc.ca.gov>)'; 'Drew, Tim G.'; 'Bender, Sylvia@Energy'; Edson, Karen
> Subject: RE: updated DRAFT for our meeting today
>
> We had a minor update since I sent this out….we will view this updated presentation on our call. Kristen
>
> 1. Include 1 page Annual view of critical milestones only
>
> 2. Updated date for Filing date for proposed amendment of TCA appendix E on Transmission track
>
> From: Kelley, Kristen
> Sent: Thursday, February 27, 2014 12:08 PM
> To: Van Pelt, Gregory; Picker, Michael; Randolph, Edward; 'Tollstrup, Michael@ARB (mtollstr@arb.ca.gov<mailto:mtollstr@arb.ca.gov>)'; Pettingill, Phil; 'Drew.Bohan@energy.ca.gov<mailto:Drew.Bohan@energy.ca.gov>'; ''Kasmar, Jeff' (Jeff.Kasmar@cpuc.ca.gov<mailto:Jeff.Kasmar@cpuc.ca.gov>)'; 'Oglesby, Rob@Energy (Rob.Oglesby@energy.ca.gov<mailto:Rob.Oglesby@energy.ca.gov>)'; 'Barker, Kevin@Energy (Kevin.Barker@energy.ca.gov<mailto:Kevin.Barker@energy.ca.gov>)'; Walker, Cynthia

(cynthia.walker@cpuc.ca.gov<mailto:cynthia.walker@cpuc.ca.gov>); 'Drew, Tim G.'; 'Bender, Sylvia@Energy'; Edson, Karen
> Subject: updated DRAFT for our meeting today
>
> Team,
> I sent out a DRAFT presentation on 2/16/14 for your review. Since, the agencies have made some updates. This revised DRAFT includes the updates I have received up to today. This presentation is what we will be discussing at today's call/WebEx. In addition, Jeff Kasmar will be introducing Tim Drew as taking over his activities.
>
> For you information, a summary of the recent changes include:
> Preferred Track
>
> 1. Removal of ISO Stakeholder process and BOG decision for an EE/DR Auction - This initiative was canceled by the ISO
>
> 2. Extension of EM&V study on Flex Alert to 2/28/14
>
> 3. Earlier completion of LTPP Track IV Proposed Decision
>
> 4. Minor date changes in Rule 24 Tariff tasks
> Conventional Gen Track
>
> 1. Renaming and adjusting Carlsbad tasks
> Transmission Track
>
> 1. Addition of CEC Fatal Flaw Analysis Completion for Albherhill/Suncrest 500 kv line (already completed)
>
> 2. Renaming of the 5/29 "evaluation" of SONGs voltage criteria adjustment to "Quantification" of the benefit
>
> 3. Removal of the task for SCE to submit NIPRS (not needed)
>
> 4. Removal of NRC Decision on SONGs voltage criteria adjustment (not needed)
> Contingency Options
>
> 1. Moving the determination of triggers/timeline from end of March to June 15, 2014
>
> 2. Adding other tasks to determine if accelerating the generation process is needed and subsequent steps
>
>
>
>
>
>
> Kristen Kelley, PMP
> California ISO Program Management Office
> Reliability Planning for LA Basin and San Diego
> Replacement Requirements for Scheduled Generation Outages
> Integrated Optimal Outage Coordination
> 916.351.2336
> 916.719.8202 cell
>
> **
> The foregoing electronic message, together with any attachments thereto, is confidential and may be legally privileged against disclosure other than to the intended recipient. It is intended solely for the addressee(s) and access to the message by anyone else is unauthorized. If you are not the intended recipient of this electronic message, you are hereby notified that any dissemination, distribution, or any action taken or omitted to be taken in reliance on it is strictly prohibited and may be unlawful. If you have received this electronic message in error, please delete and immediately notify the sender of this error.
> **
> <20140227 Southern California Reliability Planning Update_DRAFT1a.pptx>

EXHIBIT 4

Power Reactor
Facility: SAN ONOFRE
Region: 4 State: CA
Unit: [ ] [ ] [3]
RX Type: [1] W-3-LP,[2] CE,[3] CE
NRC Notified By: DOUG FOOTE
HQ OPS Officer: JOHN KNOKE
Emergency Class: NON EMERGENCY
10 CFR Section:
50.72(b)(2)(iv)(B) - RPS ACTUATION - CRITICAL

Event Number: 47628
Notification Date: 01/31/2012
Notification Time: 22:58 [ET]
Event Date: 01/31/2012
Event Time: 17:30 [PST]
Last Update Date: 01/31/2012

Person (Organization):
JEFF CLARK (R4DO)
SCOTT MORRIS (IRD)
LOUISE LUND (NRR)

Unit	SCRAM Code	RX CRIT	Initial PWR	Initial RX Mode	Current PWR	Current RX Mode
3	M/R	Y	100	Power Operation	0	Hot Standby

Event Text

MANUAL TRIP DUE TO A PRIMARY TO SECONDARY LEAK GREATER THAN 30 GAL/HR

"At 1505 PST, Unit 3 entered Abnormal Operation Instruction S023-13-14 'Reactor Coolant Leak' for a steam generator leak exceeding 5 gallons per day.

"At 1549 PST, the leak rate was determined to be 82 gallons per day. At 1610 PST, a leak rate greater than 75

gallons per day with an increasing rate of leakage exceeding 30 gallons per hour was established and entry into S023-13-28 'Rapid Power Reduction' was performed.

"At 1630 PST, commenced rapid power reduction per S023-13-28 'Rapid Power Reduction'. At 1731 PST, with reactor power at 35% the Unit was manually tripped. At 1738 PST, Unit 3 entered Emergency Operation Instruction S023-12-4 'Steam Generator Tube Rupture'.

"At 1800 PST the affected steam generator was isolated."

All control rods fully inserted on the trip. Decay heat is being removed thru the main steam bypass valves into the main condenser. Main feedwater is maintaining steam generator level. No relief valves lifted during the manual trip. The plant is in normal shutdown electrical lineup.

Unit 2 is presently in a refueling outage and was not affected by this event.

The licensee has notified the NRC Resident Inspector. The licensee has issued a press release.

Page Last Reviewed/Updated Thursday, March 29, 2012

EXHIBIT 5

ENERGY INSTITUTE AT HAAS

EI @ Haas WP 248

Market Impacts of a Nuclear Power Plant Closure

Lucas Davis and Catherine Hausman
Revised May 2015

http://ei.haas.berkeley.edu

1 Introduction

Nuclear power has historically supplied a substantial portion of electricity – 20 percent in the United States and 14 percent worldwide for 2000 to 2012. As recently as 2008, the outlook for the industry was robust, with nuclear plants earning large profits. Since 2009, however, prospects for nuclear power – even at existing facilities – have substantially waned, with the closure of several large facilities and predictions of more closures to come (EIA 2014). As we describe in detail, multiple factors have contributed to the recent closures of nuclear plants. Peak wholesale electricity prices fell around 50 percent in real terms from 2007 to 2012,[1] a result of both falling natural gas prices and stagnant electricity demand. At the same time, costs for nuclear plants have been rising, a combination of rising wages and fuel prices, stricter safety regulations, and the aging of decades-old equipment.

To many observers, low profitability at *existing* nuclear plants is surprising, since the marginal cost of generation is very low at nuclear plants. However, while marginal costs hour-to-hour are low, fixed operating costs (e.g., keeping employees on staff) are high. Total operations and maintenance (O&M) costs at U.S. nuclear plants have increased by about 20 percent in real terms since 2002 and today are more than twice as high as O&M costs at natural gas plants. These higher costs reflect the fact that nuclear plants have substantially higher requirements for safety, security, and testing.

In this paper, we use evidence from a nuclear power plant closure to examine the rapidly evolving economics of nuclear power and to assess the potential private and social consequences of plant closures. While in operation, the San Onofre Nuclear Generating Station (SONGS) generated an average of 16 million megawatt hours of electricity annually, making it the second largest electric generating facility in California. During this period, SONGS generated enough electricity to meet the needs of 2.3 million California households[2] – about 8 percent of all electricity generated in the state. SONGS was closed abruptly in February 2012, when workers discovered problems with the plant's steam generators. Although it was not known at the time, SONGS would never operate again.

The first-order effect of the plant's exit was a large inward shift of the electricity supply curve. Like other nuclear power plants, SONGS produced electricity at very low marginal cost. Consequently, the plant was always near the bottom of the supply curve, operating around the clock and providing a consistent source of electricity. When SONGS was closed, this generation had to be made up for by operating other generating resources with higher marginal cost. We use rich micro-data from a variety of sources and a novel econometric

[1] Peak wholesale prices at various hubs for ICE contracts; source: EIA. Prices throughout are deflated to 2013 dollars using the GDP deflator.

[2] U.S. DOE/EIA "Electric Sales, Revenue, and Average Price," November 2013, Tables T1 and T2. California households used an average of 6.9 megawatt hours in 2012.

method to identify those marginal resources that would be expected to increase production. We find that the lost generation from SONGS was met largely by in-state natural gas plants. Bringing these additional plants online cost an average of $63,000 per hour in the twelve months following the closure. The SONGS closure also had important implications for the environment, increasing carbon dioxide emissions by 9 million tons in the first twelve months. To put this in some perspective, this is the equivalent of putting 2 million additional cars on the road.[3]

There was also a second-order, but not insignificant, additional impact on the market. SONGS was even more valuable than these numbers suggest because of its location between Los Angeles and San Diego, two enormous demand centers. Although there is transmission that connects Southern California to the rest of the state, the capacity is limited. Prior to the closure, transmission capacity between Northern and Southern California was almost always sufficient, so that wholesale prices equalized in the two regions during the vast majority of hours. However, beginning with the closure in 2012, we document a substantial divergence in prices between Northern and Southern California. This binding transmission constraint and other physical constraints of the grid meant that it was not possible to meet all of the lost output from SONGS using the lowest cost available generating resources.

These second-order effects are reflected in our model as "residuals," measured as deviations from predicted plant behavior. We find that during low demand hours, the change in generation closely follows predictions based on pre-closure behavior, with about half of the increased generation coming from Southern California and the other half coming from Northern California. During high demand hours, however, we find significant residual effects: higher cost generating units coming online more than predicted. In high demand hours in 2012, we find that as much as 75 percent of the lost generation was met by plants located in Southern California. On average, these constraints increased generation costs by an average of $4,500 per hour, implying that the total cost of additional natural gas generation was almost $68,000 per hour in the twelve months following the closure.

These residuals also potentially reflect non-competitive behavior. Tight market conditions make it more profitable for certain firms to exercise market power, and using our model we are able to determine which individual plants changed their behavior the most after the SONGS closure. Because of the transmission constraints, the largest positive residuals are at Southern plants, and the largest negative residuals are at Northern plants. Surprisingly, we also find large negative residuals during high demand hours at two Southern plants: Alamitos and Redondo, both owned by the same company. This was unexpected but, as it turns

[3] According to U.S. DOE/EIA Annual Energy Review, September 2012, Table 2.8 "Motor Vehicle Mileage, Fuel Consumption, and Fuel Economy", light-duty vehicles with a short wheelbase use an average of 453 gallons of gasoline annually. For each gallon of gasoline, 19.6 pounds of carbon dioxide are emitted.

EXHIBIT 6

Message

From:	Stevens, Brian [brian.stevens@cpuc.ca.gov]
Sent:	4/5/2012 10:56:32 PM
To:	Randolph, Edward F. [edward.randolph@cpuc.ca.gov]; Room 5305 [room5305@cpuc.ca.gov]; Sterkel, Merideth "Molly" [merideth.sterkel@cpuc.ca.gov]; Ikle, Judith [judith.ikle@cpuc.ca.gov]; Gary.Schoonyan@sce.com; Clanon, Paul [paul.clanon@cpuc.ca.gov]; Kersten, Colette [colette.kersten@cpuc.ca.gov]; Lindh, Frank [frank.lindh@cpuc.ca.gov]; St. Marie, Stephen [stephen.stmarie@cpuc.ca.gov]; Franz, Damon A. [damon.franz@cpuc.ca.gov]; Beck, Valerie [valerie.beck@cpuc.ca.gov]; Baker, Simon [simon.baker@cpuc.ca.gov]; Liang-Uejio, Scarlett [scarlett.liang-uejio@cpuc.ca.gov]; Brown, Carol A. [carol.brown@cpuc.ca.gov]; Como, Joe [joe.como@cpuc.ca.gov]; Sandoval, Catherine J.K. [catherine.sandoval@cpuc.ca.gov]; Charkowicz, Ed [ed.charkowicz@cpuc.ca.gov]; Tisdale, Matthew [matthew.tisdale@cpuc.ca.gov]; Prosper, Terrie D. [terrie.prosper@cpuc.ca.gov]; Brooks, Donald J. [donald.brooks@cpuc.ca.gov]; Lakhchaura, Megha [megha.lakhchaura@cpuc.ca.gov]; Kaneshiro, Bruce [bruce.kaneshiro@cpuc.ca.gov]
Subject:	Notes from April 4th SCE SONGS Summer Outlook meeting
Attachments:	Notes April 4 SONGS summer planning meeting with SCE.doc

Please feel welcome to provide input on these notes to ensure I have a robust capture of the meeting.

The main action items from this meeting include:

Colette requested a page informational sheet on market monitoring from SCE

The next meeting with SCE could be next Friday the 20th before 2:00 PM:

And at a later meeting in ED regarding DR, we should plan a separate meeting with the ISO regarding DR planning

Thanks,

Brian Stevens

From: Ikle, Judith on behalf of Randolph, Edward F.
Sent: Mon 4/2/2012 10:28 AM
To: Randolph, Edward F.; Stevens, Brian; Room 5305; Sterkel, Merideth "Molly"; Ikle, Judith; 'Gary.Schoonyan@sce.com'; Clanon, Paul; Kersten, Colette; Lindh, Frank; St. Marie, Stephen; Franz, Damon A.; Beck, Valerie; Baker, Simon; Liang-Uejio, Scarlett; Brown, Carol A.; Como, Joe
Subject: FW: Updated: Meeting with SCE Follow-Up Information on Summer Supply Outlook with Gary Schoonyan

When: Wednesday, April 04, 2012 2:00 PM-3:00 PM (GMT-08:00) Pacific Time (US & Canada).

Where: Room 5305

Note: The GMT offset above does not reflect daylight saving time adjustments.

~~*~*~*~*~*~*~*~*

1) Current SONGS status

   a. Both units are still in cold shutdown

   b. Return to service forecast: Unit 2- June 1st; Unit 3 – June 16th

      i. These numbers represent the work needed to be done to get the units restarted. Parallel to this is the analysis to identify the root cause.

      ii. They do need to go to the NRC to permission to restart; these dates represent the physical work needed.

      iii. Commissioner Sandoval: If for some reason they are not able to identify the root cause, these dates should be pushed out.

      iv. The time to restart the steam units is 1-2 weeks.

      v. There is about a month of continued investigation with unit 2. They will begin restart after the NRC is satisfied and they have taken into account in unit 2 the lessons learned from unit 3.

   c. Valerie Beck: Some discussions alluded that SCE made a differentiation between root cause and direct cause. Are they making that differentiation?

      i. This is NRC correction actions speak.

      ii. The difference is to identify what happened v. why it happened. Finding the root cause of unit three is crucial to ensure it doesn't happen to unit 2.

      iii. They will need to get us to speak with the engineers for further information.

      iv. Commissioner Sandoval: The NRC letter is very concerned with why it happened not just what happened.

2) Contingency Planning Cases Being Considered

   a. **Scenario A** – Unit 2 returns to service in spring 2012 while Unit 3 remains off-line. Unit 2 trips during 2012 summer peak.

   b. **Scenario B** – Both SONGS units off-line through 2012 peak but at least one of the units return to service beginning in 2013.

3) Summer 2012 Peak Without SONGS

   a. There are still questions to answer regarding local resources in LA Basin.

      i. Including whether there will be emission issues in the Basin with whatever is necessary to replace SONGS

ii. AQMD – raising some questions about HB emissions questions – SCE's model does not take into account the diesel that will fire up in case of a blackout.

1. SCE at this point cannot add that to their model, but they can do that analysis after the fact.

iii. Carol Brown: there is the whole Port of LB issue and whether the ships can plug into electricity or run diesel (also Port of LA)

1. SCE believes this "cold ironing" issue is understood and analyzed.

iv. Carol Brown heard the AQMD does not like HB units 3 and 4 coming online, but how can they say that if they haven't modeled these other contingencies?

v. Commissioner Sandoval: emergency diesel does not ding the companies under US EPA regs. This is a major deficiency in the model.

vi. Colette: In general we have a better summary for how we are prepped for market monitoring in the summer. Prices have not been impacted even if supply is scarce, and there are other benchmarks including exceptional dispatch and congestion revenue. If we're doing our job, we need to look at specificity other than prices. REQUESTED: a page on market monitoring to leave it to their judgment as to what should be covered.

vii. SCE: we did some assessments and to date there has been no impact to price with the units out, although this summer there is a projected $/MWh increase in cost.

b. Judith: We've heard CAISO's software has caused more starts than historically has been the case; can SCE confirm?

i. Edison's 4 peakers have run more in the last year than previous in terms of starts, and the CAISO market design has changed as they are concerned about having flexible resources in real time. They have 400-700 MW/hour in standby services, and those resources are starter more than in the past.

c. Commissioner Sandoval: question about the third bullet (likely insufficient local area resources in the LA Basin without at least one of the SONGS units): What is their perspective about what this means?

i. Concern not just the LA Basin but also SD –

ii. The grid isn't as homogenous as they would like it, for procurement they need about 10,600 MW of supply in the LA Basin to meet demand, and there is a total of 12,000MW of supply in the LA Basin.

iii. With SONGS 2 and 3 out, they are 800MW short as opposed to 1,500MW long.

iv. It is in south OC where the problem is not just amount of power but the supply of vars necessary to keep voltage up. SDG&E faces the same issue.

1. OC Ellis substation, Santiago substation – from HB down to SONGS

4) Possible Generation Actions

a. They are talking with CAISO to return HB 3 and 4 – which would serve 450 MW to the grid

b. Cost to get HB running again

i. Up to $20 million

ii. AES says the gas service has been cut and there have been holes punched in the boiler for tax purposes. They can get them back online, and there is no public sign they have been demolished. It would take about 1 month to get them back online.

c. They can put trailer mounted generators at substations

i. 4 25MW generators with a total capacity of 100MW (10 million dollars/unit/year)

ii. They want to lock these down without committing for the year.

iii. There may or may not be gas lines nearby, in which case they would use diesel if not.

5) Transmission considerations

a. Voltage drop

i. They put in systems such that there are relays so if voltage drops, they drop significant load to maintain the system reliability.

1. The load drop is 1,500 MW.

ii. They are forced because of the time constraints so they would be dropping load at the four south OC substations.

1. The system is "smart" and would drop 1 to 4 substations as needed

2. The substations are Ellis – HB, Viejo – Lake Forest, Santiago – Irvine, and Johanna – Santa Ana: These are the substations closest to SONGS.

3. If HB 3 and 4 are available, these contingencies are still necessary

iii. Community outreach on this topic is needed.

1. Commissioner Sandoval: the community outreach needs to not only say what is happening, but it needs to be explicit about what denizens of the area need to do to respond. Also, the outreach must be towards nontraditional media and being multi-lingual: specifically in Spanish, Vietnamese, and Chinese.

2. And we need to use weather forecasts to see this coming in advance

   a. SCE explains that the marine layer in this area during this time is very unpredictable and thus can cause the temperature to change up to 10 degrees without notice.

iv. Coordination with SD – because this is the southern part of SCE near northern SDG&E, any contingency would impact them too.

6) Demand Side Resource Summary

a. Key Programs

i. Summer discount plan is AC cycling – 50MW of curtailment potential in those 4 substations available. They have potential for 5-8 MW through a couple of measures (more customers on the program, replacing the switches on the ACs that might not be working)

1. There is no correlation between the customer participation and which substation will be shut off first – just the substation with the lowest voltage.

ii. Base interruptible program

1. 30 MW of load reduction potential for those customers. Right now they don't geographically dispatch this program.

iii. There is 27 more MW in the programs if users turn their base generators on to participate in the event. There are policy issues at AQMD, although the CPUC tariff allows for this. However, a clarification from the CPUC allowing it would be helpful, and a CPUC or Gov's office declaration of emergency might be necessary to get AQMD on board.

1. The current permits only allow the generators to run if there is a blackout not to run to prevent a blackout.

iv. Other 2012 DR and conservation options

1. 20/20 potential reeffectuate
    a. 11 MW for commercial customers only
    b. SCE will file an advice letter seeking approval to move forward
    c. During the energy crisis it wasn't just commercial, not now the non commercial programs are covered by other programs.
    d. Startup cost would be 200k for marketing, outreach, and billing changes.
2. Signing the contract with Mcguire this week
    a. This would be a robust program to explain what you need to do in a flex your power situation over the course of the summer.
    b. Commissioner Sandoval – They have yet to sign a contract
        i. Do they have in the contract stuff for outreach for multilingual people, non traditional media sources, the Santa Ana area has a lot of Latinos and Vietnamese people.
        ii. SCE – yes, this is multi lingual, and it is similar to the advertisements of the past.
        iii. We need to be cautious that we don't replicate the past because last September she heard an ad that didn't explain what to do – don't repeat that.
        iv. Commissioner Sandoval "The takes are high, and we're trying to prevent a blackout – we need to make sure we get the message right."
    c. From an internal proposal, they asked Wally to provide a 6, 8, and 10 million dollar proposal.
        i. The 10 million dollar proposal might be state wide – and we should target the affected areas.
    d. Ed Randolph: We can help with free media campaigns, as well, through the CPUC and Governor's Office.

7) Electric Emergency Action Plan

a. Every year they file this plan with the CAISO and ED, and they are working on it to coordinate the changes necessary for this year.

b. They are not starting from scratch here – augmenting last year's plan

c. Ed Randolph: one DR question, we've had spirited conversations with CAISO over our DR forecast v. theirs and he they would incorporate DR programs into their forecast. For all DR programs they have, how do they anticipate these programs get used and help reduce the cost of having other resources on standby?

    i. SCE has other DR resources available to dispatch on a day ahead economic basis, and they can do it when the forecast for energy is at a trigger point.

    ii. This includes aggregation with EnerNOC, and critical peak pricing that is their dynamic pricing. The summer discount plan and AC cycle program is 60MW another AC program is 650 MW, so when they have a system wide event, they can dispatch 1000 MW of most of the programs.

d. Scarlet: What about south of Lugo? SCE seemed to be focusing only on south OC. The ISO asked for DR mapping in that location only.

    i. Yes, what is available with the DR is the summer response program that can be dispatched south of Lugo. They are working for geographical dispatch on the main four, not south of Lugo.

8) Next meeting?

a. It can be the 23rd or Friday the 20th before 2:00 PM.

    i. Prior to that meeting, SCE will try to put together an agenda to put together the items.

9) Post SCE DR discussion

a. Should we derate the MW of available due to customer fatigue after on a third consecutive day? Specifically for the agriculture pump and AC cycling.

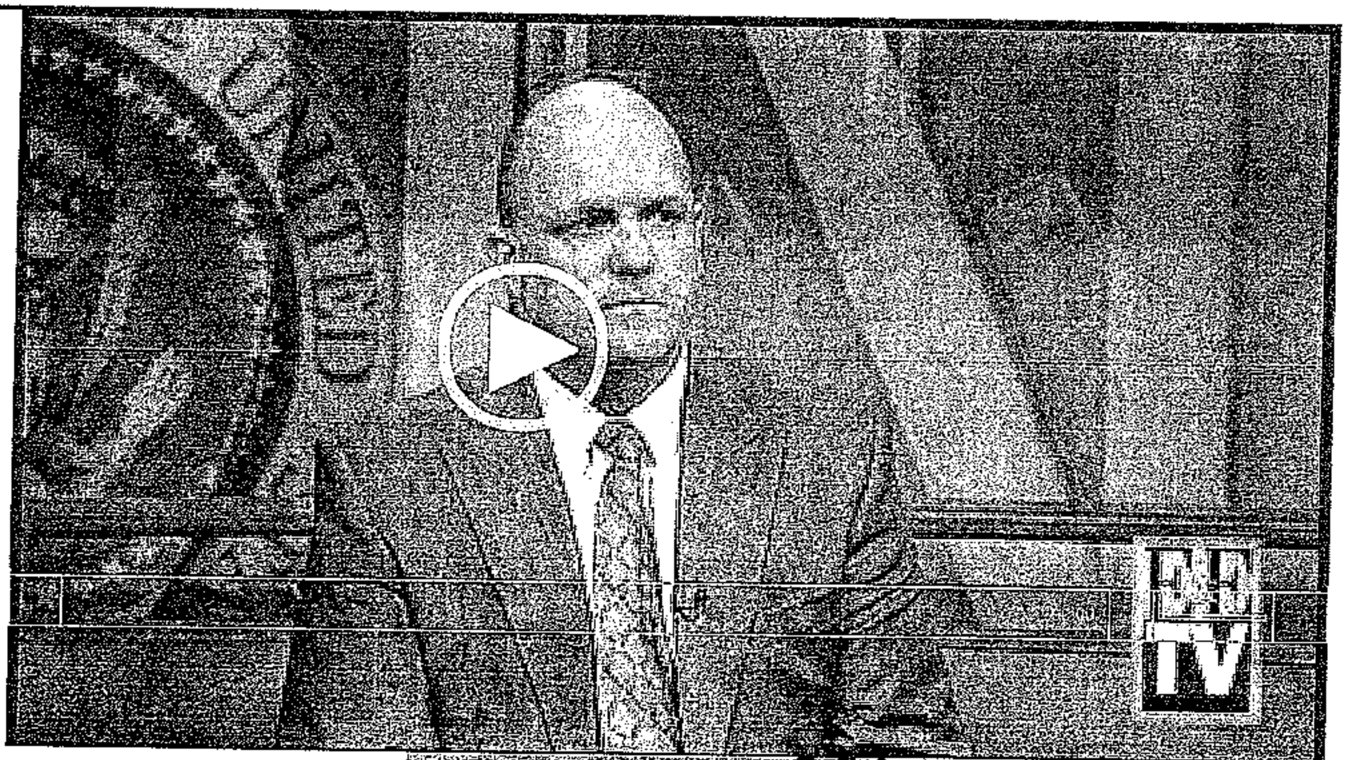
    i. We have data that says for these programs there is no customer fatigue from day 1 to day 2, but there is no data on what happens in day 3.

        1. Simon thinks the biggest risk is going to the ISO and saying we're giving these DR programs a haircut because there would be some fatigue even there is no data.

        2. The question here is what is the sunk cost?

3. We should follow up with the CAISO in a separate meeting not the Friday meetings.

EXHIBIT 7



TRANSMISSION:

California ISO's Berberich discusses impact of San Onofre shutdown on reliability

OnPoint: Wednesday, April 18, 2012

How has California's transmission reliability been affected by the shutdown of the San Onofre nuclear facility, and issues with the Sutter Energy natural gas facility? During today's OnPoint, Stephen Berberich, president and CEO at the California ISO, discusses California's reliability challenges and clean energy accomplishments.

Filter by: enter keyword go!

Sorted by: Date Topic

Results 1 - 10 of 1589

EXHIBIT 8

California Energy Commission California Public Utilities Commission California ISO

2012 Summer Readiness

Robert Weisenmiller
Chair of the California Energy Commission

Paul Clanon
Executive Director of the California Public Utilities Commission

Steve Berberich
Chief Executive Officer of the California Independent System Operator

May 7, 2012

CEC statewide planning studies and ISO operational studies essentially agree.

- On a statewide and ISO system basis, supply is adequate to cover a broad range of potential peak demand conditions and contingencies.
- The absence of the San Onofre nuclear plant does not create system-wide issues but does create local reliability issues because of transmission constraints that limit imports into the Los Angeles Basin and San Diego areas.

The ISO's longer-term studies start with the CEC demand forecast.

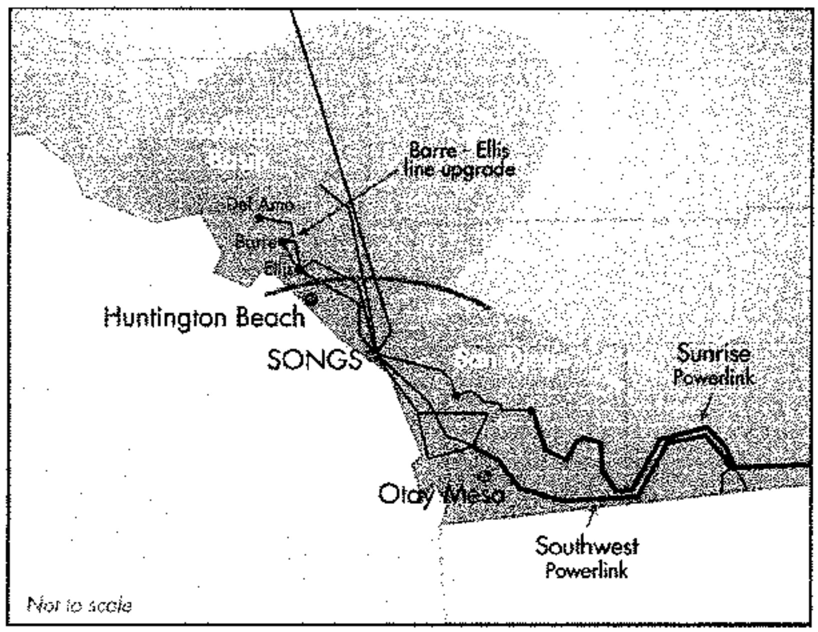
- Every year the ISO publishes studies looking out 10 years and five years, as well as seasonal studies throughout the year to determine reliability needs and challenges.

- The ISO must comply with federal reliability standards and more rigorous California supplemental standards by being constantly prepared for the loss of a single generator and various combinations of transmission system outages.

- Study work started in 2011 is being augmented in the 2012-2013 transmission plan to address possible long-term outages of the San Onofre and Diablo Canyon nuclear power plants.

Reliability issues arise in the LA Basin and San Diego without the San Onofre nuclear power plant.

- Los Angeles Basin and San Diego areas must have local generation to serve all consumers
- The ISO already plans for the outage of one San Onofre generating unit
- ISO must plan for the major contingencies where San Diego loses eastern transmission and the largest generator



San Diego and the Los Angeles Basin are at risk of outages under required planning standards.

San Diego

Without both San Onofre units -

Import capability ⬇

Total gen	+3,048
Import capability	+2,100
Largest generation outage	- 603
Load	-4,882
Shortfall	= - 337

Los Angeles Basin

Without both San Onofre Units –

Total gen ⬇

Total gen *	+9,418
Import capability **	+10,771
Largest generation outage ***	- 498
Load	-19,931
Shortfall	= **-240**

Notes:
* Installed capacity, some of which is not under contract.
** Transmission import capability is subject to change, as system conditions change from year to year.
***Largest generating unit outage after both San Onofre units are out of service .

Restarting existing, permitted generation is essential.

San Diego

Without SONGS and with Huntington Beach 3 & 4 –

Import capability ↑

Total gen	+ 3,048
Import capability	+ 2,450
Largest generation outage	- 603
Load	- 4,882
Surplus	= 13

Los Angeles Basin

Without SONGS and with Huntington Beach 3 & 4 –

Total gen ↑

Total gen*	+ 9, 870
Import capability**	+10,771
Largest generation outage	- 498
Load	- 19,931
Surplus*	= 212

Notes:
* Installed capacity, some of which is not under contract.
** Transmission import capability is subject to change, as system conditions change from year to year.
***Largest generating unit outage after both San Onofre units are out of service .

Conservation and demand response increase the margins.

Energy conservation and demand response will increase the margin.

		Existing DR MWs
SCE	All demand response programs	1,700 MW
	Southern Orange County and South of Lugo	506 MW
SDG&E	All demand response programs	104 MW

- SCE and SDG&E proposals for additional MWs are awaiting Commission approval.
- The Commission has authorized $10 million for the Flex Alert campaign, a mass media program that informs the general public on how to reduce their energy usage and alerts them to reduce when CAISO needs additional reductions.
- The education effort includes outreach to disadvantaged communities and foreign language speakers.
- In the event of an emergency, procedures include notification of the California Emergency Management Agency and affected utilities who manage local communication and urgent response processes.

Actions are underway to mitigate the risk of outages.

- Return Huntington Beach units 3 & 4 to service
- Accelerate Barre-Ellis transmission upgrade
- Complete Sunrise transmission line and related outage planning
- Fully fund Flex Alerts
- Fully utilize available demand response
- Seek additional military and public agency demand response
- Ensure that existing generation is well-maintained and available

EXHIBIT 9

Message

From:	Peevey, Michael R. [michael.peevey@cpuc.ca.gov]
Sent:	10/13/2012 12:15:03 AM
To:	Ron.Litzinger@sce.com
Subject:	RE: Huntington Beach Synchronous Condensers

I re-confirm.

From: Ron.Litzinger@sce.com [Ron.Litzinger@sce.com]
Sent: Friday, October 12, 2012 5:13 PM
To: Michael Peevey
Subject: Huntington Beach Synchronous Condensers

Mike,

Thanks for the call yesterday regarding the Huntington Beach Sychronous Condensers. The call was timely as Steve Berberich from CAISO had called me earlier about signing an agreement to backstop AES expenditures for the equipment while a Reliability Must Run (RMR) agreement is negotiated. We certainly share your concern about grid reliability and are willing to consider reasonable measures for Summer 2013 preparedness. I appreciated your sharing with me the your support and the support of the CPUC, CAISO and the Governor's Office.

We are concerned about AES inability thus far to get JP Morgan consent to the equipment under their tolling agreement. We appreciate CAISO's plan to overcome this obstacle, but remain concerned after review of the plan by our legal team and outside counsel.

We appreciate both your assurance on the call yesterday as well as your letter on September 4 for cost recovery should an RMR not be executed. Based on everyone's mutual desire for grid reliability, I am willing to instruct the team to sign the backstop agreement. I would appreciate re-confirmation of assurance of reasonable cost recovery.

Thanks Mike.

PRA1262-0001875

ACA 11 - 00216

EXHIBIT 10

Goldthrite, Cody

From: Ron.Litzinger@sce.com
Sent: Wednesday, June 12, 2013 4:34 PM
To: Berberich, Steve
Cc: Wallerstein Barry (bwallerstein@aqmd.gov); Felicia Marcus (felicia.marcus@waterboards.ca.gov); Edson, Karen; Peevey, Michael R. (michael.peevey@cpuc.ca.gov); Picker, Michael; Niggli, Michael; Weisenmiller, Robert@Energy (Robert.Weisenmiller@energy.ca.gov); stephen.pickett@sce.com
Subject: Re: Loss of SONGS Task Force

Steve Pickett. for us

From: 1 "Berberich, Steve" <SBerberich@caiso.com>
To: "Peevey, Michael R. (michael.peevey@cpuc.ca.gov)" <michael.peevey@cpuc.ca.gov>, 2 "Weisenmiller, Robert@Energy (Robert.Weisenmiller@energy.ca.gov)" <Robert.Weisenmiller@energy.ca.gov>, "Niggli, Michael" <mniggli@semprautilities.com>, 5 "Ron.Litzinger@sce.com" <Ron.Litzinger@sce.com>, "Wallerstein Barry (bwallerstein@aqmd.gov)" <bwallerstein@aqmd.gov>, "Felicia Marcus (felicia.marcus@waterboards.ca.gov)" <felicia.marcus@waterboards.ca.gov>, 6 7
Cc: "Picker, Michael" <Michael.Picker@gov.ca.gov>, "Edson, Karen" <KEdson@caiso.com>
Date: 06/12/2013 10:28 AM
Subject: Loss of SONGS Task Force

The governor has asked for a 90 day report on how reliability will be maintained with the permanent loss of SONGS. In discussions with Mike Peevey, Mike and I agreed that the best approach would be to form a task force from the PUC, CEC, ISO, SCE, SDG&E, SCAQMD and the Water Board to address a number of issues including the following:

- What mix of resources and assets would best meet reliability needs at the lowest cost and with least regrets for long term system planning?
- What near term, mid term and long term actions should be taken to replace San Onofre energy and voltage support?
- What conventional, distributed generation could be contingency permitted and sited?
- How can we solve the loss yet minimize the amount of replacement power emissions?
- What OTC plants should be moved on for repower and which ones should be considered for compliance date extensions?
- How can demand response, energy efficiency and other emerging technologies play a role in in minimizing conventional generation solutions?

The ISO will take the lead in getting the task force coordinated and Neil Millar, our head of system planning, will be the lead on our end. Please let me know who from your organization will participate in the task force. We anticipate the initial meeting to take place in Folsom at the ISO with subsequent meetings in S. California. Finally, I propose that we have monthly meetings with Michael Picker of the governor's office and agency and utilities heads to monitor progress of the task force. As always, I welcome comments and alternative suggestions for moving forward.

Best regards,

Steve

EXHIBIT 11

Message

From:	Picker, Michael [Michael.Picker@cpuc.ca.gov]
Sent:	8/11/2014 6:09:42 PM
To:	'Edson, Karen' [KEdson@caiso.com]
Subject:	RE: IID deliverability issue
Attachments:	image001.jpg; image002.jpg; image003.jpg; image004.jpg; image005.jpg; image006.jpg; image007.jpg

He still believes that you guys told him that there was adequate transmission capacity to move 500 MW of geothermal to the coast; and that (not clear that he actually asked the question) geothermal from Imperial is just what is needed to replace San Onofre.

I said that Kevin Kelley was wrong about how to reach the Imperial County deliverability and that the physics of the system made it unlikely that additional remove resources help with reliability on the coast without another set of transmission improvements that provide delivery (or VARS) at someplace near San Onofre.

He said that the didn't understand what a VAR was, and then went on to complain about the CPUC leg staff's testimony about economic impacts.

Commissioner Michael Picker

California Public Utilities Commission

505 Van Ness, Fifth Floor

San Francisco, CA 94102

(415) 703-2444

Michael.Picker@cpuc.ca.gov

From: Edson, Karen [mailto:KEdson@caiso.com]
Sent: Friday, August 08, 2014 4:22 PM
To: Picker, Michael
Subject: IID deliverability issue

Michael,

EXHIBIT 12

State of California California Energy Commission

Memorandum

To: Robert Weisenmiller, Chair Travel Date: Monday, July 8, 2013

From: Catherine Cross, Administrative Assistant Subject: Post SONGS Strategy Dinner

Monday, July 8, 2013

What: Post SONGS Strategy Dinner (*Attendees pay for their own food/drinks*)

Location: President Peevey has reserved a private room on the 3rd floor of the California Club 538 South Flower Street, Los Angeles, CA 90071

Time: 6:00 -9:00 pm (6:00 Drinks – 6:30 pm Dinner)

Contact: Kim Hubner, *email:* khubner@caiso.com

Catherine Ohaegbu

Subject:	Post SONGS Strategy Dinner
Location:	California Club - 538 S. Flower St, Los Angeles - Private room on 3rd floor
Start:	Mon 7/8/2013 6:00 PM
End:	Mon 7/8/2013 9:00 PM
Show Time As:	Tentative
Recurrence:	(none)
Meeting Status:	Accepted
Organizer:	Berberich, Steve
Required Attendees:	mp1@cpuc.ca.gov; 'Mary Nichols'; bwallerstein@aqmd.gov; Weisenmiller, Robert@Energy (Robert.Weisenmiller@energy.ca.gov); Michael Picker; 'Marcus Felicia - State Water Resources Control Board (felicia.marcus@waterboards.ca.gov)'; 'michael.rossi@gov.ca.gov'

EXHIBIT 13

Message

From:	Picker, Michael [Michael.Picker@cpuc.ca.gov]
Sent:	8/11/2014 6:09:42 PM
To:	'Edson, Karen' [KEdson@caiso.com]
Subject:	RE: IID deliverability issue
Attachments:	image001.jpg; image002.jpg; image003.jpg; image004.jpg; image005.jpg; image006.jpg; image007.jpg

He still believes that you guys told him that there was adequate transmission capacity to move 500 MW of geothermal to the coast; and that (not clear that he actually asked the question) geothermal from Imperial is just what is needed to replace San Onofre.

I said that Kevin Kelley was wrong about how to reach the Imperial County deliverability and that the physics of the system made it unlikely that additional remove resources help with reliability on the coast without another set of transmission improvements that provide delivery (or VARS) at someplace near San Onofre.

He said that the didn't understand what a VAR was, and then went on to complain about the CPUC leg staff's testimony about economic impacts.

Commissioner Michael Picker

California Public Utilities Commission

505 Van Ness, Fifth Floor

San Francisco, CA 94102

(415) 703-2444

Michael.Picker@cpuc.ca.gov

From: Edson, Karen [mailto:KEdson@caiso.com]
Sent: Friday, August 08, 2014 4:22 PM
To: Picker, Michael
Subject: IID deliverability issue

Michael,

Below is Mary McDonald's email to Martha Guzman regarding deliverability from IID. As the email indicates, Kevin Kelley misunderstood the issue we tried to clarify in this document -- http://www.caiso.com/Documents/TechnicalAddendum-ImperialCountyDeliverability.pdf -- and made incorrect representations to the Legislature. Let me know if you have questions.

Karen Edson

From: McDonald, Mary
Sent: Friday, August 08, 2014 4:09 PM
To: Martha Guzman-Aceves
Cc: Edson, Karen; Layton, Katie
Subject: FW: SB 1139

Hi Martha,

At this week's Assembly Appropriations Committee hearing on SB 1139 (Hueso), Kevin Kelley the General Manager of Imperial Irrigation District stated that a recent ISO technical addendum finds that 462 MW of export capacity available from IID into the ISO (http://www.caiso.com/Documents/TechnicalAddendum-ImperialCountyDeliverability.pdf). However, that 462 MW that he referenced is being used to import existing generation from IID into the ISO (Maximum Import Capability, MIC). As explained in the addendum, transmission additions approved in the ISO's 2013-14 transmission planning cycle will enable future additional amount of deliverability for the overall Imperial zone of up to 1,000 MW. Based on a review of the CPUC's approved power purchase agreements we have determined that all of the 1,000 MW is expected to be used by generation that is already moving forward as a result of having CPUC approval and are connecting directly to the ISO. I should also note at the request of the CPUC/CEC we are studying a scenario that would see an increase of 2,500 MW from the IID zone. Finally, also as part of this year's transmission plan we are also exploring how to achieve additional deliverability from the Imperial zone part of the 2014-15 plan. We are exploring options that include relatively low cost transmission operation changes, upgrades and re-purposing that could potentially provide several hundred MWs of additional deliverability from the Imperial zone. This afternoon, Karen Edson the ISO's VP of Policy and Client Services spoke with Kevin Kelley about his statement in Assembly Appropriations Committee and they discussed the ISO's addendum and he now has a clearer understanding.

The following is an excerpt of what Kelley said at the Assembly Appropriations Committee Hearing:

Kevin Kelley:

"In past committees, it's been testified by the regulators that IID has zero export capacity into the ISO system. I listened to that repeatedly and so I went to the ISO to correct the record. And I commend to you this technical

addendum which was published to the ISO website last week that places the current export capacity from IID to the ISO system at 462 MW. That's today, and that's without building any new transmission. The closing thought I'd like to leave you with is it's been said that this bill if it were to be enacted does nothing for the Salton Sea. It's true this bill is silent on the Salton Sea, but this bill is looked at as a first step in something like a self-help regiment to the Salton Sea. It serves our region's interest, it serves the public's interest, and the Salton Sea can't wait much longer."

Please feel free to contact me with any questions.

Have a great weekend

Mary

California ISO

Mary McDonald

Director of State Government Affairs

250 Outcropping Way

Folsom, CA 95630

phone: (916) 802-3576 | fax: (916) 608-5070

Please consider the environment before printing this email

EXHIBIT 14

Message

From:	Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
on behalf of	Cross, Catherine@Energy [Catherine.Cross@energy.ca.gov]
Sent:	6/10/2014 12:32:11 AM
To:	Nichols, Mary D. @ARB [mnichols@arb.ca.gov]; Scott, Janea@Energy [janea.scott@energy.ca.gov]; Steve Berberich [sberberich@caiso.com]; Michael R. Peevey [mp1@cpuc.ca.gov]; michael.picker@cpuc.ca.gov; Rechtschaffen, Cliff [cliff.rechtschaffen@gov.ca.gov]; Wallerstein Barry (bwallerstein@aqmd.gov) [bwallerstein@aqmd.gov]; Marcus, Felicia@Waterboards [Felicia.Marcus@waterboards.ca.gov]; Oglesby, Rob@Energy [Rob.Oglesby@energy.ca.gov]; Barker, Kevin@Energy [Kevin.Barker@energy.ca.gov]; brian.turner@cpuc.ca.gov
CC:	Stewart, Shannon@ARB [snstewar@arb.ca.gov]; Lorton, Michele@Energy [michele.lorton@energy.ca.gov]; Darlene Stasky (dstasky@caiso.com) [dstasky@caiso.com]; Nuria Gonzalez [nuria.gonzalez@cpuc.ca.gov]; Lynn Sadler (ls1@cpuc.ca.gov) [ls1@cpuc.ca.gov]; Juliane Banks [juliane.banks@cpuc.ca.gov]; Natalie Murphey (Natalie.Murphey@gov.ca.gov) [Natalie.Murphey@gov.ca.gov]; Denise Whitcher (dwhitcher@aqmd.gov) [dwhitcher@aqmd.gov]; Barrios, Alicia@Waterboards [Alicia.Barrios@Waterboards.ca.gov]; Kessler, Rebecca@Energy [rebecca.kessler@energy.ca.gov]; Ernst, Laura@Energy [laura.ernst@energy.ca.gov]
Subject:	SONGS/California Reliability Meeting

When: Tuesday, June 17, 2014 3:15 PM-5:00 PM (GMT-08:00) Pacific Time (US & Canada).
Where: Mary Nichols' Residence, Redacted

Note: The GMT offset above does not reflect daylight saving time adjustments.

~~*~*~*~*~*~*~*~*

Please note that meeting time/information has changed – see below:

Meeting will commence at approximately 3:15 pm and is being held at Mary Nichol's residence **(located approximately 30 minutes from Burbank/Bob Hope Airport.)**
Dinner will be catered.

Google map from Burbank Airport to Redacted
Google map from Redacted **to Burbank Airport:** Redacted
After meeting:

Traveling from Burbank to Sacramento:
Southwest Flight 146 departs Burbank @ 9:10 pm/arrives Sacramento 10:20 pm

Traveling from Burbank to Oakland:
Southwest Flight 660 departs Burbank @ 8:55 pm/arrives Oakland 10:00 pm

Participants:

<u>Air Resources Board</u>
Mary Nichols

<u>California Energy Commission</u>
Rob Oglesby

Janea Scott
Bob Weisenmiller

California ISO
Steve Berberich

California Public Utilities Commission
Michael Peevey
Michael Picker

Governor's Office
Cliff Rechtschaffen

South Coast Air Quality Management District
Barry Wallerstein

State Water Resources Control Board
Felicia Marcus (unable to attend)

EXHIBIT 15

Appointment

From:	Ann Davey/SCE/EIX [Ann.Davey@sce.com] 1
To:	Ann Davey/SCE/EIX [Ann.Davey@sce.com]; fohreraj@gmail.com; 2 LEGIONARY44BC@ICLOUD.COM; 3 mp1@cpuc.ca.gov; Stephen E Pickett/SCE/EIX [Stephen.Pickett@sce.com] 4
CC:	nuria.gonzalez@cpuc.ca.gov
Subject:	Dinner Meeting (Mike Peevey, Al Fohrer, Bob Foster & Steve Pickett)
Location:	California Club, 538 South Flower, Los Angeles (Dinner will be served in the 3rd Floor Bar; Reservations under "Al Fohrer")
Start:	12/14/2013 2:00:00 AM
End:	12/14/2013 4:00:00 AM
Show Time As:	Tentative
Recurrence:	(none)

EXHIBIT 16

Sent: Monday, April 27, 2015 9:23 AM
To: ORDONEZ Jorge; Dalley, Bryce
Subject: RE: PacifiCorp to Explore Becoming Transmission at CALISO

Thanks Jorge – to get you started, here are some links where you will be able to obtain a FAQs on our study to join the CAISO and also the MOU between PacifiCorp and CAISO.

http://www.pacificorp.com/about/newsroom/2015nrl/study-joining-california-iso.html

http://www.caiso.com/informed/Pages/StakeholderProcesses/PacifiCorp.aspx

I think it will provide most of what you're looking for. Please take a look and let us know what gaps we can help fill.

Thanks,
Natasha

From: ORDONEZ Jorge [mailto:jorge.ordonez@state.or.us]
Sent: Monday, April 27, 2015 8:46 AM
To: Dalley, Bryce
Cc: Siores, Natasha
Subject: PacifiCorp to Explore Becoming Transmission at CALISO

Hi Bryce,

I called you this morning and also left a voicemail to Natasha.

I've been tasked to provide the PUC chairman with an update about PacifiCorp's exploration to become a transmission owner at the CALISO. I plan to prepare something very high level (a very few number paragraphs). Could you please help me describing the following?:

General description of what is the project about;
The filing requirements from the PUC that PacifiCorp might have to provide in the case of moving forward with this.

Please give me a call or stop by my desk. Your secretary told me that you are in Salem today.

Thanks!

Jorge

Jorge Ordonez
Senior Financial Economist
Energy Resources and Planning
Oregon Public Utility Commission
jorge.ordonez@state.or.us

From: Siores, Natasha
To: ORDONEZ Jorge; Dalley, Bryce
Subject: RE: PacifiCorp to Explore Becoming Transmission at CALISO
Date: Monday, April 27, 2015 2:17:12 PM

Jorge,

I asked the legal team working on this and they indicated that our initial review indicated that we would likely need to seek approval to transfer operation of public utility property and the performance of public utility services to the ISO under ORS §757.480. I hope this is helpful for your write-up.

Thanks,
Natasha

From: ORDONEZ Jorge [mailto:jorge.ordonez@state.or.us]
Sent: Monday, April 27, 2015 10:04 AM
To: Siores, Natasha; Dalley, Bryce
Subject: RE: PacifiCorp to Explore Becoming Transmission at CALISO

Thanks Natasha for the links!

Could you please let me know what are the filing requirements from the PUC that PacifiCorp might have to provide in the case of moving forward with this? I understand that you are in the preliminary stages of this, but I suppose that you may have entertain very superficially this matter. That would be very helpful.

Jorge

From: Siores, Natasha [mailto:Natasha.Siores@pacificorp.com]
Sent: Monday, April 27, 2015 9:23 AM
To: ORDONEZ Jorge; Dalley, Bryce
Subject: RE: PacifiCorp to Explore Becoming Transmission at CALISO

Thanks Jorge – to get you started, here are some links where you will be able to obtain a FAQs on our study to join the CAISO and also the MOU between PacifiCorp and CAISO.

http://www.pacificorp.com/about/newsroom/2015nrl/study-joining-california-iso.html

http://www.caiso.com/informed/Pages/StakeholderProcesses/PacifiCorp.aspx

I think it will provide most of what you're looking for. Please take a look and let us know what gaps we can help fill.

From:	Apperson, Erin
To:	ORDONEZ Jorge
Subject:	RE: California ISO- PacifiCorp meeting with Commissioner Savage of 9/14/2015
Date:	Wednesday, September 23, 2015 4:44:55 PM

I just confirmed with Bryce that it was in fact Phil Pettingill (contact info below).

From: ORDONEZ Jorge [mailto:jorge.ordonez@state.or.us]
Sent: Wednesday, September 23, 2015 3:05 PM
To: Apperson, Erin
Subject: RE: California ISO- PacifiCorp meeting with Commissioner Savage of 9/14/2015

I don't know. I was not able to understand his name (he spoke too quickly). The only think I know is that he was a man.

From: Apperson, Erin [mailto:Erin.Apperson@pacificorp.com]
Sent: Wednesday, September 23, 2015 3:04 PM
To: ORDONEZ Jorge
Subject: RE: California ISO- PacifiCorp meeting with Commissioner Savage of 9/14/2015

Was it Phil Pettingill? PPettingill@caiso.com

From: ORDONEZ Jorge [mailto:jorge.ordonez@state.or.us]
Sent: Wednesday, September 23, 2015 3:03 PM
To: Apperson, Erin
Subject: RE: California ISO- PacifiCorp meeting with Commissioner Savage of 9/14/2015

Thanks Erin. One piece is missing: what is the name of the CAISO gentleman present in the meeting with Commissioner Savage?

Regards,

Jorge

From: Apperson, Erin [mailto:Erin.Apperson@pacificorp.com]
Sent: Wednesday, September 23, 2015 3:00 PM
To: ORDONEZ Jorge
Subject: RE: California ISO- PacifiCorp meeting with Commissioner Savage of 9/14/2015

Jorge,

Apologies for the delay on responding to this request. I've received the following names for contacts for you at the CPUC: Jason Ortego, 415-703-4773, jason.ortego@cpuc.ca.gov; and Robert Strauss, Robert.strauss@cpuc.ca.gov.

You had also asked about the contact information for the ISO: Stacy Crowley (scrowley@caiso.com).

Lastly, you asked about some of the industry meeting occurring that are dealing with the CAISO.

- See here for a link to the CAISO Stakeholder Symposium: https://www.caiso.com/informed/Pages/MeetingsEvents/PublicForums/Default.aspx. It appears that Commissioner Savage is on a panel on October 22.
- See here for a link to the CREPC-SPSC-WIRAB Meeting: http://westernenergyboard.org/2015/09/joint-crepc-spsc-wirab-meeting/
- PacifiCorp and the CAISO Markets Outreach meeting is scheduled for November 20 in Portland, but I do not currently have any additional information on that meeting

Erin Apperson
Manager, Regulatory Affairs
|503-813-6642 office |206-406-0042 cellular | erin.apperson@pacificorp.com

---

From: ORDONEZ Jorge [mailto:jorge.ordonez@state.or.us]
Sent: Tuesday, September 15, 2015 5:20 PM
To: Apperson, Erin
Cc: Siores, Natasha
Subject: California ISO- PacifiCorp meeting with Commissioner Savage of 9/14/2015

Erin,

In yesterday's meeting Bryce suggested that I should contact you to follow up on a couple of things. Could you please:

Send the contact information of the person of the California ISO in the meeting?
Send the contact information of the persons at the California PUC who deal with the California ISO aspects of its IOUs? To have context, the person of the California ISO informally mentioned that they are around four California PUC Staff members.

Regards,

Jorge

Jorge Ordonez
Senior Economist
Energy Resources and Planning
Public Utility Commission of Oregon
jorge.ordonez@state.or.us
Phone: 503-378-4629
Fax: 503-373-7752

EXHIBIT 17

Senate Bill No. 350

Passed the Senate September 11, 2015

____
Secretary of the Senate

Passed the Assembly September 11, 2015

____
Chief Clerk of the Assembly

This bill was received by the Governor this ________ day of ______________, 2015, at _____ o'clock ____M.

____
Private Secretary of the Governor

Senate Bill No. 350

CHAPTER 547

An act to add Section 44258.5 to the Health and Safety Code, to amend Section 1720 of the Labor Code, to amend Sections 25310 and 25943 of, and to add Sections 25302.2 and 25327 to, the Public Resources Code, and to amend Sections 359, 399.4, 399.11, 399.12, 399.13, 399.15, 399.16, 399.18, 399.21, 399.30, 454.55, 454.56, 701.1, 740.8, 9505, and 9620 of, to amend and repeal Sections 337 and 352 of, to add Sections 237.5, 365.2, 366.3, 454.51, 454.52, 740.12, 9621, and 9622 to, to add Article 17 (commencing with Section 400) to Chapter 2.3 of Part 1 of Division 1 of, to add and repeal Article 5.5 (commencing with Section 359.5) of Chapter 2.3 of Part 1 of Division 1 of, and to repeal Article 5 (commencing with Section 359) of Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to energy.

[Approved by Governor October 7, 2015. Filed with Secretary of State October 7, 2015.]

LEGISLATIVE COUNSEL'S DIGEST

SB 350, De León. Clean Energy and Pollution Reduction Act of 2015.

(1) Under existing law, the Public Utilities Commission (PUC) has regulatory jurisdiction over public utilities, including electrical corporations, community choice aggregators, and electric service providers, while local publicly owned electric utilities are under the direction of their governing boards. Existing law imposes various regulations on public utilities and local publicly owned electric utilities. Existing law establishes the California Renewables Portfolio Standards (RPS) Program, which is codified in the Public Utilities Act, with the target to increase the amount of electricity generated per year from eligible renewable energy resources to an amount that equals at least 33% of the total electricity sold to retail customers per year by December 31, 2020. Under existing law, a violation of the Public Utilities Act is a crime.

This bill would require that the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50% by December 31, 2030, as provided. The bill would make other revisions to the RPS Program and to certain other requirements on public utilities and publicly owned electric utilities.

Because certain of the above provisions are codified in the Public Utilities Act, this bill would impose a state-mandated local program by expanding the definition of a crime or establishing a new crime.

(2) Existing law requires the PUC to identify cost-effective electricity efficiency savings and establish efficiency targets for an electrical corporation to achieve, and to identify cost-effective natural gas efficiency

Michael J. Aguirre, Esq., SBN 060402
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San Diego, CA 92101
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Attorneys for Petitioner

SUPERIOR COURT OF THE STATE OF CALIFORNIA

COUNTY OF IMPERIAL

IMPERIAL IRRIGATION DISTRICT, Petitioner, v. CALIFORNIA INDEPENDENT SYSTEM OPERATOR, and DOES 1-20, inclusive, Respondents,	Case No. **PETITION FOR WRIT OF MANDAMUS AND COMPLAINT FOR INJUNCTIVE DECLARATORY RELIEF UNDER CALIFORNIA'S PUBLIC RECORD LAWS**

I.

INTRODUCTION

1. Petitioner the Imperial Irrigation District (IID), entered the power industry in 1936. Today, IID serves electricity to more than 145,000 customers in Imperial County, California and parts of Riverside and San Diego counties. IID is the largest irrigation district in the nation.

2. Respondent California Independent System Operator (CAISO) is supposed to be a **non-profit** public interest corporation organized under the laws of the State of California. Under California Public Utilities Code § 337(a), CAISO board of directors shall be composed of a five-member independent governing board of directors appointed by the Governor and subject to confirmation by the Senate. Under California Public Utilities Code § 345.5, CAISO shall make

the most efficient use of available energy resources, reduce overall economic cost to the state's consumers, conform CAISO decisions to state law intended to protect the public's health and the environment, maximize availability of existing electric generation resources necessary to meet the needs of the state's electricity consumers, conduct internal operations in a manner that minimizes cost impact on ratepayers, communicate with all balancing area authorities in California in a manner that supports electrical reliability, consult and coordinate with appropriate local agencies to ensure CAISO operates in furtherance of state law regarding consumer and environmental protection, and ensure that CAISO’s purposes and functions are consistent with the purposes and functions of nonprofit, public benefit corporations in the state, including duties of care and conflict-of-interest standards for officers and directors of a corporation.

3. Under California Public Utilities Code § 345.5(c)(3), CAISO is required to maintain open meeting standards and meeting notice requirements consistent with the general policies of the Bagley-Keene Open Meeting Act (Article 9 (commencing with Section 11120) of Chapter 1 of Part 1 of Division 3 of Title 2 of the Government Code) and afford the public the greatest possible access, consistent with other duties of the corporation. [1]

4. Under California Public Utilities Code § 345.5(c)(4), CAISO is required to provide public access to corporate records consistent with the general policies of the California Public Records Act [Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code] and affording the public the greatest possible access, consistent with the other duties of the corporation.[2] (California Public Records Law)

5. Petitioner IID is located in the City of El Centro, which encompasses all of Imperial County. The IID does business with CAISO from IID operating headquarters which is located at 333 East Barioni Boulevard, Imperial County, CA 92251.

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[1] Pub. Util. Code. § 345.5(c)(3) provides: CAISO Open Meeting Policy, as adopted on April 23, 1998, and in effect as of May 1, 2002, meets the requirements of this paragraph. The Independent System Operator shall maintain a policy that is no less consistent with the Bagley-Keene Open Meeting Act than its policy in effect as of May 1, 2002.

[2] Pub. Util. Code § 345.5 (c)(4) provides: The CAISO Information Availability Policy, as adopted on October 22, 1998, and in effect as of May 1, 2002, meets the requirements of this paragraph. The CAISO shall maintain a policy that is no less consistent with the California Public Records Act than its policy in effect as of May 1, 2002.

II.

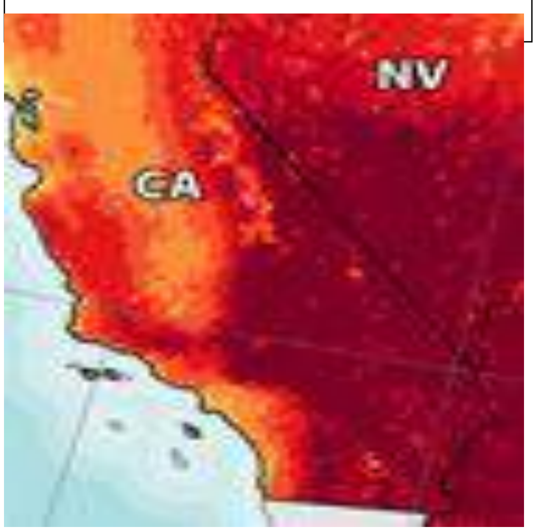
SUMMARY OF ALLEGATIONS

6. Imperial County, California ranks among the top agricultural counties in the nation. IID is the largest irrigation district in the nation, and the sixth largest electrical utility in California serving more than 150,000 customers.

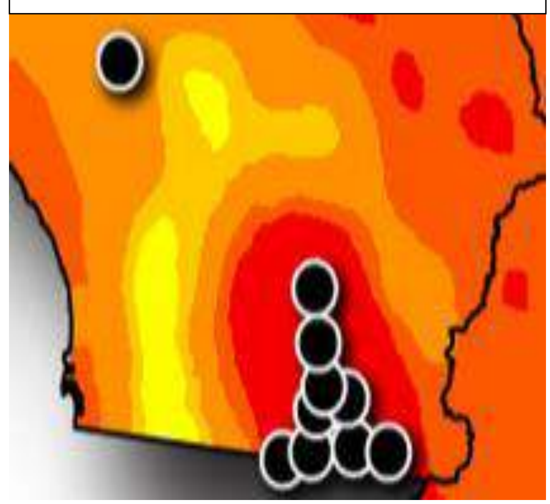
A. IMPERIAL VALLEY RENEWABLE ENERGY FOR CALIFORNIA

7. Over **8,480** megawatts (MW) of renewable energy has been identified as available for development in Imperial County, according to California's lead energy agencies. Further, the United States government's primary laboratory for renewable energy, energy efficiency research, and development -- the National Renewable Energy Laboratory (NREL) -- has identified Imperial County as some of the most favorable regions for solar and geothermal energy in the nation, as shown here on two NREL energy potential maps:

NREL Map Solar Resources Concentrated in Imperial County



NREL Gives Imperial County Most Favorable Geothermal Rating

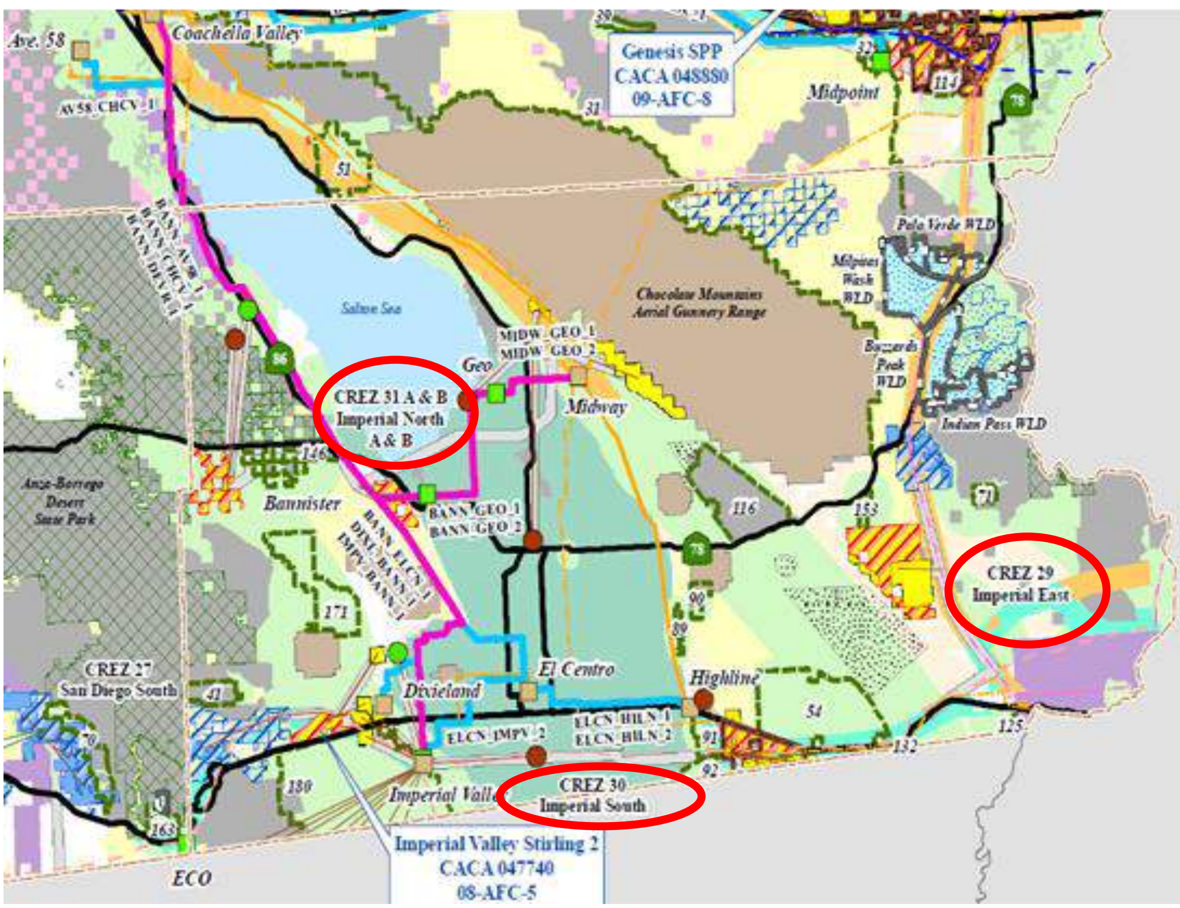


8. The California Public Utilities Commission (CPUC), California Energy Commission (CEC), and CAISO, as part their collaborative, created a "Renewable Energy Transmission Initiative" (RETI) to identify the transmission projects needed to accommodate California's renewable energy goals. Competitive Renewable Energy Zones (CREZs) were

identified for areas with the greatest potential for cost-effective and environmentally responsible renewable development. In 2010, the following renewable energy zones were identified in the IID areas with 8,489 MW of four types of renewable energy:

	Biomass	Geothermal	Solar Thermal	Wind	Total
Imperial East	-	-	1,500	74	1,574
Imperial North-A	-	1,370	-	0	1,370
Imperial North-B	30	0	1,800	0	1,830
Imperial South	36	64	3,570	45	3,715
TOTAL	66	1,434	6,870	119	**8,489**

9. The RETI report identified four Competitive Renewable Energy Zones (CREZ) in Imperial Valley (1. Imperial East 29; 2. Imperial South 30; 3. Imperial North 31A; and 4. Imperial North 31 B) all of which are mostly located in the heart of IID's service areas:



/ / /

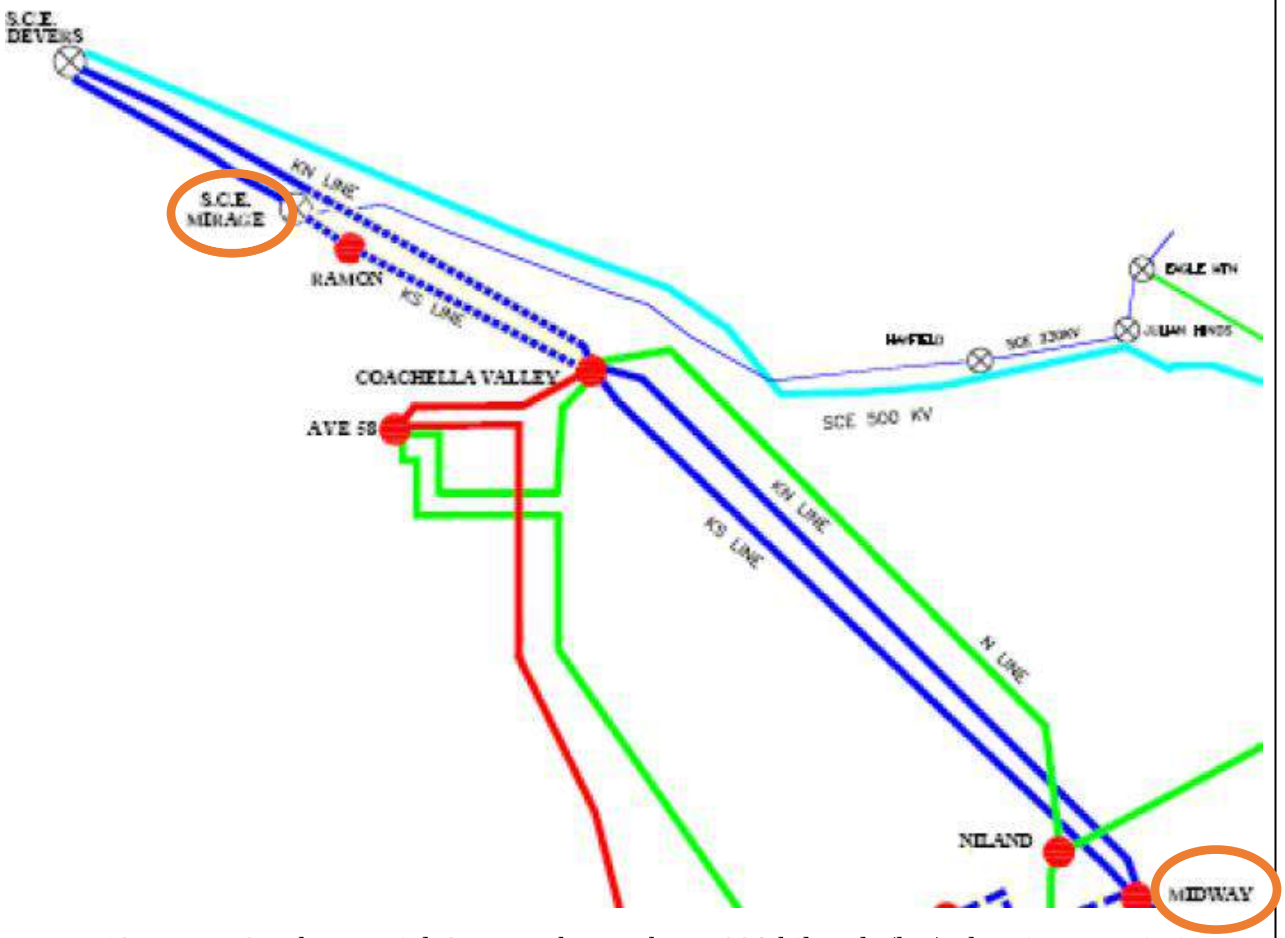
10. Geothermal resources in Imperial Valley are located principally in the north part of Imperial County, or CREZ 31A and CREZ 31B:

Cluster of 7 Geothermal Plants in North Imperial Irrigation District Territory

11. While solar power resources are not limited to any one part of IID's territory, they are principally located in Imperial South near Mount Signal, or CREZ 30:

B. IID TRANSMISSION LINES CAN TRANSPORT RENEWABLE ENERGY

12. IID has two electric transmission lines (the "KN/KS line") connecting the Imperial Valley geothermal and solar renewable resources through the Midway substation to the CAISO at the Mirage substation:



13. In South Imperial County, the IID has a 230 kilovolt (kV) electric transmission line (the "S line") connecting the Imperial Valley geothermal and solar renewable resources to the CAISO at the Imperial Valley substation:

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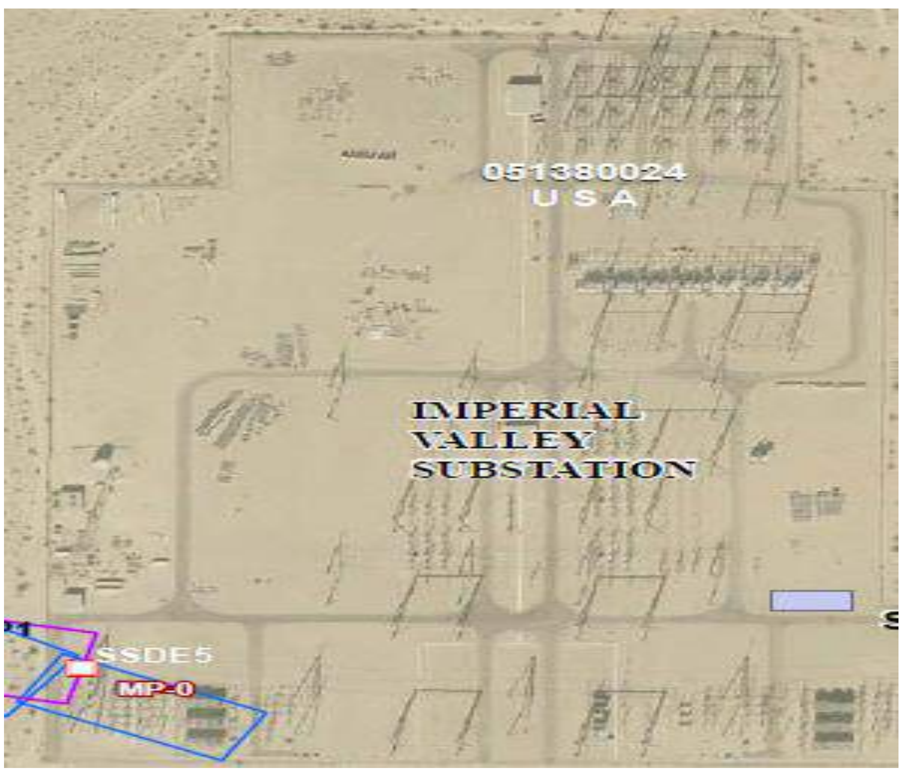
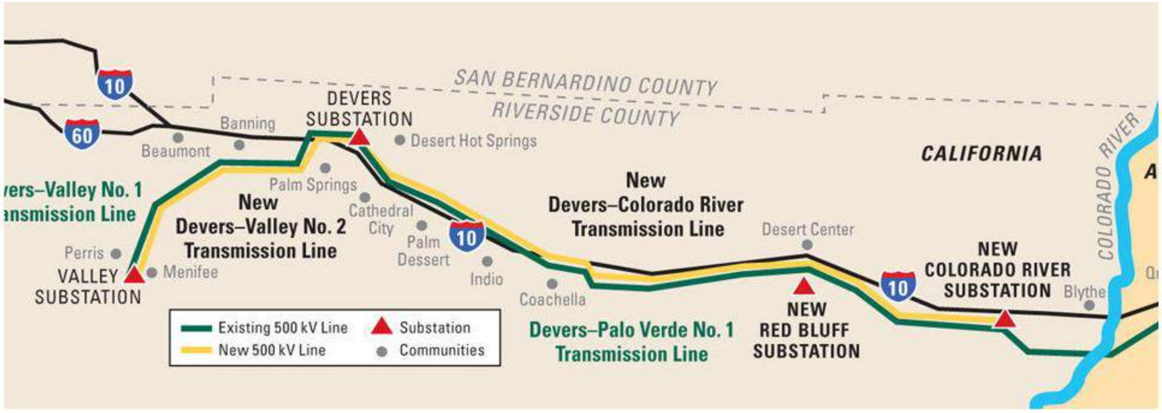
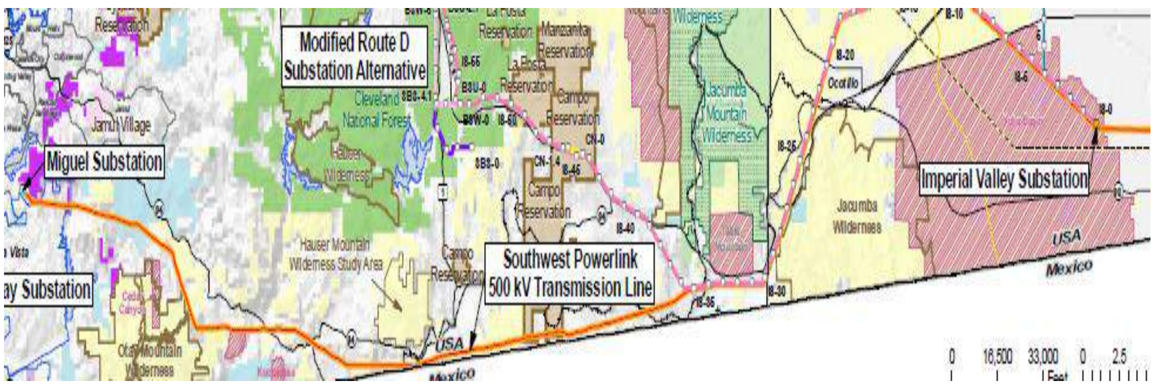


14. Once the renewable energy transported on IID's 230 kV lines (the KN and KS lines) reaches the Mirage Substation, it is stepped up to 500 kV and carried on CAISO's 500 kV lines to load serving utilities:



15. Once the renewable energy transported on IID's 230 kV lines (the S line) reaches the Imperial Valley Substation, it is stepped up to 500 kV and carried on CAISO's two 500 kV lines to load serving utilities:



16. As of December 31, 2014, California has 21,000 MW of renewable energy (18,800 MW Wholesale; 2,200 MW Self-generation). On September 14, 2015, CAISO estimated peak daily demand at around 36,744 MW (on the high side of daily peak demand). Imperial County has significant amounts of undeveloped renewable geothermal energy capable of serving load that produces less greenhouse gases than traditional alternatives.

17. Rather than support the development of Imperial Valley's geothermal and other renewable energy, CAISO is blocking its development because the renewable energy would have to be transported through the IID balancing authority. This would produce wheeling fees for IID, thereby strengthening IID's financial condition and ability to provide low cost electricity.

18. Under California Public Utilities Code § 345.5, CAISO is failing to make the most efficient use of available energy resources, reduce overall economic cost to the state's consumers, conform CAISO decisions to state law intended to protect the public's health and the

environment, maximize availability of existing electric generation resources necessary to meet the needs of the state's electricity consumers, conduct internal operations in a manner that minimizes cost impact on ratepayers, communicate with all balancing area authorities in California in a manner that supports electrical reliability, or to consult and coordinate with appropriate local agencies to ensure CAISO operates in furtherance of state law regarding consumer and environmental protection as required by statute.

19. Under California Public Utilities Code § 345.5(c)(3), CAISO is not meeting its duty to maintain open meeting standards and meeting notice requirements consistent with the general policies of the Bagley-Keene Open Meeting Act (Article 9 (commencing with Section 11120) of Chapter 1 of Part 1 of Division 3 of Title 2 of the Government Code) and afford the public the greatest possible access, consistent with other duties of the corporation.

20. Under California Public Utilities Code § 345.5(c)(4), CAISO is not meeting its duty to provide public access to corporate records consistent with the general policies of the California Public Records Act [Chapter 3.5 (commencing with Section 6250) of Division 7 of Title 1 of the Government Code] or to afford the public the greatest possible access, consistent with the other duties of the corporation. (California Public Records Law)

21. CAISO leadership is moving in the opposite direction; it now seeks to remove itself from the regulatory jurisdiction of the State of California by expanding its jurisdiction to include Oregon, Wyoming, Utah, and Arizona.

22. Numerous questions have arisen as to why CAISO does not allow the IID to fully utilize its renewable resource potential and how easier access to renewable generation from other balancing authorities within the state of California could be obtained.

23. In order to explore these areas of important public interest and to be able to consider alternative policies, IID has requested but has not received meaningful response to the following records requests for writings under California’s Public Records Law.

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III.

REQUESTS FOR RECORDS OF COMMUNICATION UNDER CALIFORNIA PUBLIC RECORDS LAW

1. **Request #1 for Communications Regarding the MIC Assigned to IID from 2011 to Date**

24. On July 2, 2015, pursuant to California Public Records Law, the IID requested any writings, as defined by California Evidence Code §250, related to the "Maximum Import Capability [MIC] of renewable energy from the Imperial Irrigation District (IID) territory or the Imperial Competitive Renewable Energy Zone (CREZ) for the period of January 2011 to date."

25. The IID requested these communications from key decision makers at CAISO including: the Board of Governors (Ashutosh Bhagwat, Angelina Galiteva, Richard Maullin, and David Olsen); the President and Chief Executive Officer (Stephen Berberich); Officers of the Market and Infrastructure Development (Keith Casey, Robert Sparks, and Neil Miller); Officers of the Policy & Client Services Section (Karen Edson, Tom Cuccia, and Dennis Peters); and transmission engineers (Songzhe Zhu, Yi Zhang, Hong Zhou, and Binaya Shrestha). These writings were specifically requested to discover any communications that had taken place at CAISO regarding the decision that there was no availability on CAISO's transmission lines for the renewable energy in Imperial County.

26. CAISO initially refused to provide any responsive documents. To this day, CAISO has failed to produce a single email or record of communication relating to IID's MIC from the period of January 2011 to date. However, CAISO produced 17,000 pages of pdfs which are simply lifted off of its website, and are not even logically unitized. A review of that massive data dump reveals that it does not contain any emails or text messages (and attachments). Accordingly, this petition is necessary for IID to obtain the public records which CAISO is required by law to produce.

2. **Request #2 for Communications Regarding Change to IID MIC for 2016**

27. On July 13, 2015, pursuant to California Public Records Law, the IID requested "all records of communication" relating to a letter dated 9 July 2015 from Neil Millar (CAISO

Executive Director of infrastructure development) to Carl Stills (IID Energy Manager) titled "Imperial Irrigation District Balancing Authority Area 2016 Maximum Import Capability" (MIC). The IID addressed this request for communications to Neil Millar as he was the author of the letter containing information regarding the identification of "additional deliverability for 2016 for the Imperial area."

28. By requesting communications regarding the change in MIC, the IID was trying to discover how CAISO determined the potential for additional deliverability. The July 9, 2015 letter also stated CAISO's intent "to adjust the MIC upward and conduct future planning activities to maintain that level going forward to reflect the generation development that has taken place in IID and have capacity contracts with CAISO load serving entities, once the necessary transmission upgrades are in place."

29. CAISO has failed to produce a single email or record of communication regarding the letter dated July 9, 2015, or the IID's 2016 MIC as determined by CAISO.

3. Request #3 for Communications Regarding the ISO 2010/2011 Transmission Plan Memorandum and Upgrades to Path 42

30. On July 21, 2015, pursuant to California Public Records Law, the IID requested any communications "mentioning or relating to the CAISO Memorandum regarding the Decision on the ISO 2010/2011 Transmission Plan dated May 11, 2011 and the policy-driven transmission upgrades to the Devers-Mirage 230kV double circuit line (Path 42)."

31. The IID sent this request to IID's Senior Counsel, pursuant to a July 17, 2015 letter, in which CAISO requested "all future communications regarding" records requests from the IID be directed to his attention as senior counsel.

32. CAISO has failed to produce a single email or record of communication regarding the decision-making process which resulted in the finding that Path 42 was a policy-driven element necessary to support California renewable energy goals.

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4. Request #4 for Communications Regarding the July 30, 2014 Technical Addendum to the July 2, 2014 Imperial County Transmission Consultation Draft Discussion Paper

33. On July 21, 2015, pursuant to California Public Records Law, the IID sent a written request to CAISO requesting any communications "relating to the July 30, 2014 Technical Addendum to the July 2, 2014 Imperial Country Transmission Consultation Draft Discussion Paper."

34. CAISO has failed to produce a single email or record of communication relating to the technical addendum to the Imperial County Transmission consultation that discussed current resource deliverability capabilities from Imperial Valley.

5. Request #5 for Communications Mentioning or Relating to the IID and the Joint Letter Dated April 18, 2011

35. On July 21, 2015, pursuant to California Public Records Law, the IID sent a written request to CAISO requesting any communications "mentioning or relating to the Imperial Irrigation District (IID) and the joint letter dated April 18, 2011 to Mr. Picker, senior advisor in the California Governor's office, regarding resource adequacy deliverability."

36. CAISO has failed to produce a single email or record of communication regarding the letter to Mr. Picker from CASIO regarding the IID and resource adequacy.

6. Request #6 for Communications Regarding the 2011/2012 Conceptual Statewide Transmission Plan Update and Upgrades to Path 42

37. On July 21, 2015, pursuant to California Public Records Law, the IID sent a written request to CAISO requesting any communications "mentioning or relating to the 2011/2012 Conceptual Statewide Transmission Plan Update and the transmission upgrades to Path 42."

38. CAISO has failed to produce a single email or record of communication mentioning or relating to the 2011/2012 Conceptual Statewide Transmission Plan Update and the transmission upgrades to Path 42 relating to the IID.

/ / /

7. Request #7 for Communications between CAISO and the Federal Energy Regulatory Commission (FERC) regarding the IID

39. On July 24, 2015, pursuant to California Public Records Law, the IID sent a written request to CAISO requesting any communications between CAISO and FERC “from January 1, 2011 to present in which the words "Imperial Irrigation District" or its acronym, "IID" appear.”

40. This request specifically identified that its intent was to request “letters, notes, memoranda, emails, text messages, and calendar invites.”

41. CAISO has failed to produce a single email or record of communication between themselves and FERC relating to the IID.

8. Request #8 IID Sent A Compilation of All Previous Requests for Communications

42. On July 29, 2015, the IID copied every single previous written request for communications to the CAISO Public Records Request Coordinator, as previous requests directed to IID’s Senior Counsel, pursuant to his request, did not result in the production of a single communication. In this written request, the IID offered to work with CAISO to accommodate production of records sought by the most efficient means possible.

43. CAISO again failed to produce a single email or record of communication in response to the compilation of IID’s previous requests for communications.

9. Request #9 for Communications relating to Project No. 104, the West of Devers Interim Project

44. On August 4, 2015, pursuant to California Public Records Law, the IID requested all communications with any officer, employee or agent of CAISO and Southern California Edison (SCE) relating to Project No. 104 - West of Devers (WOD) Interim Project.

45. CAISO again failed to produce a single email or record of communication regarding the West of Devers Interim Project.

/ / /

10. Request #10 for Communications relating to Project No. 24, Path 42 Upgrade

46. On August 4, 2015, pursuant to California Public Records Law, the IID requested all communications with any officer, employee or agent of CAISO and SCE relating to Project No. 24, or the Path 42 upgrade.

47. CAISO failed to produce a single email or record of communication regarding the Path 42 Upgrade.

FAILURE TO PRODUCE RECORDS UNDER CAL. PUB. UTILITY CODE § 345.5

48. CAISO has failed to produce any emails or records of communication in response to the requests for records made under the California public records law. CAISO conducts business on two levels: (1) For public consumption CAISO, has an elaborate public process which is mostly superfluous to the behind-the-scenes decision-making process; and (2) behind closed doors. An example of the backroom wheeling and dealing at CAISO arose after the San Onfore Power Plant failed, removing its load-serving 2200 MW from the grid. Rather than work to develop load-serving geothermal power from Imperial Valley, CAISO executives formed a "Loss of Songs Task Force" from which IID was excluded from any meaningful role, and which did not reasonably consider the geothermal alternative from the Imperial Valley.

PRAYER

Wherefore, Petitioner prays as follows:

1. An order requiring CAISO to produce to Petitioner the requested communications, including emails, required under the California public records law;
2. For attorney's fees and costs;
3. For all other relief the Court determines is warranted.

Respectfully submitted,

AGUIRRE & SEVERSON, LLP

Dated: October 9, 2015

Michael J. Aguirre
Attorney for Petitioner

EXHIBIT 3

CULTURE OF SECRECTY AND COMPLEXITY DISASTER AT CPUC

The CPUC conducts the important part of its proceedings in secret. CPUC commissioners and staff leak inside information about future CPUC policies in meetings at Wall Street, the CPUC office in San Francisco, in exclusive restaurants and members-only clubs in Los Angeles. The amount of money utility customers have to pay under contracts the CPUC authorizes to buy electricity are blacked out so utility customers see the costs. The CPUC keeps hidden the key documents in proceedings before the CPUC supposedly held to determine if utilities have acted illegally. This memorandum outlines the culture of secrecy and provides representative examples.

In 2002 the legislature enacted Pub. Util Code § 454.5 which took away the used and useful standard historically used to protect utility customers from unreasonable costs. Under the used and useful standard utilities had to prove costs were reasonable before they could be imposed on utility cusotmers. The new law (Sect. 454.5) changed the paradigm from after-the-fact review to upfront approval.

The CPUC claims the utilities "must show that their proposed procurement will provide safe, reliable capacity which complies with State policies and is at the least cost to ratepayers." The CPUC under the Long Term Procurement Plan (LTPP) supposedly takes a 10-year-ahead look at system, local, and flexible electricity needs.

The assumptions used in this evaluation are included in the documents used to support this memorandum.

One the assumptions are set and the needs identified the CPUC authorizes procurement in the form of a Commission Decision. The most recent example of this was D.14-03-004 which authorized procurement in SCE and SDG&E territories to replace electricity lost when San Onfore's new generators failed 11 after they were installed.

The CPUC adopts rules that supposedly govern the electricity procurement process. However, the key parts of the procurement is done in secret. Instead of public scrutiny, the CPUC uses "Independent Evaluators" to monitor the cost-effectiveness and overall appropriateness of transactions again in secret. The CPUC claims it does quarterly audits.

The procurement plans detail what is going to be procured and how it will be done. Utilities are supposed to submit proposed long term procurement via applications.

These seek approval of contracts or authority to build utility-owned resources. While oppositions can be filed, the CPUC makes the decisions in secret after consulting with utility executives and Wall Street insiders. For example, the decision on replacement power for San Onofre was made in a series of secret meetings at the California Club in Los Angeles and Mary Nichols (head of the Air Resources Board) personal residence.

SCE replaced San Onofre with electricity from gas fired plants. The CPUC allowed SCE to buy control of those plants using the informal advisory letter route to approve SCE's purchase.

The seller was JP Morgan. The sale occurred when FERC was in the middle of an investigation that showed JP Morgan had fraudulently manipulated the prices it charged for electricity from these plants, resulting in a half-billion dollar fine. The relevant pages are attached. As can be seen in its related attachment, the CPUC allowed terms of SCE's purchase of the generators JP Morgan used to commit illegal electricity price manipulation to remain secret.

The culture of secrecy and complexity at the CPUC hides the policy decisions that leaves utility customers paying amongst the highest rates in the country while using amongst the lowest amounts of electricity. The secrecy and complexity also conceals the fact that California is not achieving meaningful reductions in carbon emissions. The over dependence on gas fired generators to replace the generation lost at San Onofre has stressed the gas system to the breaking point. It is no exaggeration to say the radiation leak at San Onofre in 2012 led to the gas leak at Aliso Canyon in 2014. See Picker presentation to Senate Utilities Committee slides 4 and 5 attached explaining that Aliso is needed to supply the San Onofre replacement power plants with natural gas.

Message

From: Peevey, Michael R. [michael.peevey@cpuc.ca.gov]
Sent: 10/13/2012 12:15:03 AM
To: Ron.Litzinger@sce.com
Subject: RE: Huntington Beach Synchronous Condensers

I re-confirm.

From: Ron.Litzinger@sce.com [Ron.Litzinger@sce.com]
Sent: Friday, October 12, 2012 5:13 PM
To: Michael Peevey
Subject: Huntington Beach Synchronous Condensers

Mike,

Thanks for the call yesterday regarding the Huntington Beach Sychronous Condensers. The call was timely as Steve Berberich from CAISO had called me earlier about signing an agreement to backstop AES expenditures for the equipment while a Reliability Must Run (RMR) agreement is negotiated. We certainly share your concern about grid reliability and are willing to consider reasonable measures for Summer 2013 preparedness. I appreciated your sharing with me the your support and the support of the CPUC, CAISO and the Governor's Office.

We are concerned about AES inability thus far to get JP Morgan consent to the equipment under their tolling agreement. We appreciate CAISO's plan to overcome this obstacle, but remain concerned after review of the plan by our legal team and outside counsel.

We appreciate both your assurance on the call yesterday as well as your letter on September 4 for cost recovery should an RMR not be executed. Based on everyone's mutual desire for grid reliability, I am willing to instruct the team to sign the backstop agreement. I would appreciate re-confirmation of assurance of reasonable cost recovery.

Thanks Mike.

PUBLIC UTILITIES COMMISSION
SAN FRANCISCO, CA 94102-3298

July 2, 2013

Advice Letter 2853-E

Akbar Jazayeri
Vice President, Regulatory Operations
Southern California Edison Company
P O Box 800
Rosemead, CA 91770

SUBJECT: Bilateral Capacity Sale and Tolling Agreement Between SCE and BE CA LLC

Dear Mr. Jazayeri:

Advice Letter 2853-E is effective, per Ordering Paragraph in Resolution E-4584, as of May 9, 2013.

Sincerely,

Edward Randolph

Edward F. Randolph, Director
Energy Division

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Akbar Jazayeri
Vice President of Regulatory Operations

February 15, 2013

ADVICE 2853-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Bilateral Capacity Sale and Tolling Agreement Between Southern California Edison Company and BE CA LLC

I. PURPOSE

The purpose of this Advice Letter is to seek California Public Utilities Commission ("Commission" or "CPUC") approval of the bilaterally-negotiated Capacity Sale and Tolling Agreement (the "BECA Contract") between Southern California Edison Company ("SCE") and BE CA LLC ("BECA"), a subsidiary of JPMorgan Chase & Co. ("JPMorgan") and J.P. Morgan Energy Ventures Corporation ("JPMVEC"). The BECA Contract will provide SCE with energy, capacity, ancillary services, and Resource Adequacy ("RA") benefits for a term beginning on October 1, 2013, and ending on May 31, 2018, via a tolling arrangement for 12 existing generating units located in the Los Angeles Basin local area ("LA Basin").

A summary of the BECA Contract is included below.

Seller	Resource Type	Location	RA Capacity	Contract Capacity	Product	Term of Agreement
BECA	Natural gas-fired	LA Basin (Long Beach for the Alamitos Generating Station, Huntington Beach, and Redondo Beach)	3,818 MW	3,690 MW	Energy, capacity, ancillary services, and RA benefits (including all RA attributes such as local RA and the as yet to be determined flexible RA product, to the extent the units can provide them)	56 months

As discussed below and in the Appendices to this Advice Letter, the Commission should approve the BECA Contract because it provides significant, unique benefits at a reasonable price. In particular, approval of the BECA Contract will eliminate the contractual barriers to the operation of synchronous condensers at Huntington Beach Generating Station Units 3 and 4, which the California Independent System Operator ("CAISO") has determined are needed to provide voltage support this summer. Approval of the BECA Contract will also avoid Capacity Procurement Mechanism designations for the generating units included in the agreement and may also result in a decrease in Exceptional Dispatches and the costs for such Exceptional Dispatches when they do occur, which would result in cost savings for SCE's customers. Additionally, the BECA Contract will provide SCE and its customers with critical LA Basin resources to meet local RA requirements. Finally, the BECA Contract acts as a hedge against future capacity price increases and will alleviate near-term market power concerns in solicitations for LA Basin RA capacity.

SCE respectfully requests that the Commission approve this Advice Letter on an expedited basis. As explained in more detail in Sections IV.A and XII below, the CAISO has concluded that synchronous condensers at Huntington Beach Units 3 and 4 are needed to provide voltage support in summer 2013 with a planned in-service date of June 1, 2013. Final and non-appealable Commission approval of the BECA Contract will allow the synchronous condensers to be placed in operation. Accordingly, SCE requests that the Commission issue a resolution containing the findings requested in this Advice Letter by no later than May 9, 2013, which would allow sufficient time for the synchronous condensers to be placed in operation for the peak summer season.

In accordance with General Order ("GO") 96-B, the confidentiality of information included in this Advice Letter is described below. This Advice Letter contains both confidential and public appendices as listed below.

Confidential/Public Appendix A:	Contract and Valuation Information
Confidential/Public Appendix B:	RA, Capacity, and Energy Positions
Confidential Appendix C:	BECA Contract
Public Appendix D:	Confidentiality Declaration
Public Appendix E:	Proposed Protective Order

II. BACKGROUND

A. General Project Description

The BECA Contract provides SCE with the tolling rights to 12 generating units at the Alamitos, Huntington Beach, and Redondo Beach Generating Stations (collectively, the "AES 4000"), which are owned and operated by three subsidiaries of The AES Corporation ("AES"), AES Alamitos, L.L.C., AES Huntington Beach, L.L.C, and AES Redondo Beach, L.L.C. (collectively, the "AES Subsidiaries").

The AES 4000 fleet consists of existing natural gas-fired steam boiler electric generating facilities located at various strategic locations throughout the LA Basin. The Alamitos Generating Station is located in Long Beach, California, the Huntington Beach Generating Station is located in Huntington Beach, California, and the Redondo Beach Generating Station is located in Redondo Beach, California. Each generating facility is subject to the State Water Resources Control Board's ("SWRCB's") once-through cooling ("OTC") policy and has a SWRCB OTC compliance deadline of December 31, 2020.

The specific AES 4000 generating units included in the BECA Contract and their corresponding capacity are listed in the table below.

Generating Facility	Unit	RA Capacity (MW)	Contract Capacity (MW)
Alamitos Generating Station	AL1	174.56	175
	AL2	175.00	175
	AL3	332.18	320
	AL4	335.67	320
	AL5	497.97	480
	AL6	495.00	480
Huntington Beach Generating Station	HB1	225.75	215
	HB2	225.80	215
Redondo Beach Generating Station	RB5	178.87	175
	RB6	175.00	175
	RB7	505.96	480
	RB8	495.90	480
	Total	**3817.66**	**3,690**

B. Negotiation of the BECA Contract

On May 1, 1998, Williams Power Company, Inc. (formerly known as Williams Energy Services Company) ("Williams Power") and the AES Subsidiaries entered into a Capacity Sale and Tolling Agreement (as amended and supplemented, the "Base Agreement")[1] for the tolling rights to 14 generating units at the AES 4000.[2] The term of the Base Agreement ends on May 31, 2018.

In 2007, BECA, then a subsidiary of Bear Stearns Companies, Inc. ("Bear Stearns"), acquired Williams Power's rights under the Base Agreement. During the financial crisis in 2008, JPMorgan acquired Bear Stearns. With this series of events, JPMorgan, through its newly-acquired subsidiary BECA, acquired the Base Agreement.

1 The Base Agreement is included as Exhibit A to the BECA Contract, which is included as Appendix C to this Advice Letter. The Base Agreement is also publicly available at http://www.cers.water.ca.gov/pdf_files/power_contracts/williams/111902wllmsPPA.pdf.

2 The Base Agreement currently covers 12 AES 4000 generating units.

Since obtaining the rights to the AES 4000 as set forth in the Base Agreement, JPMorgan, on behalf of its subsidiary BECA, has participated in SCE's annual All-Source Requests for Offers ("RFOs") and, through those solicitations, has resold some of its tolling and RA rights from the AES 4000 to SCE. In particular, as explained in more detail in Appendix A, SCE and BECA are currently parties to two unit contingent tolling agreements with RA covering two AES 4000 units and 18 RA agreements covering several AES 4000 units.

The existing volumes and terms of SCE's unit contingent tolling agreements with RA for AES 4000 units are included in the table below.

Generating Facility	Unit	Contract Capacity (MW)	Term
Alamitos Generating Station	AL5	497.97	Jan 2011-Sept 2013
Huntington Beach Generating Station	HB2	225.80	Jan 2012-Sept 2013

The existing volumes and terms of SCE's RA agreements for AES 4000 units are included in the table below.

Generating Facility	Unit	Contract and RA Capacity (MW)	Term
Alamitos Generating Station	AL1	174.56	Jan-Dec 2013, 2014
	AL2	175.00	Jan-Dec 2013, 2014
	AL3	332.18	Jan-Dec 2013
	AL4	335.67	Jan-Dec 2013
	AL5	497.97	Jan-Dec 2015
	AL6	495.00	Jan-Dec 2013, 2014, 2015
Huntington Beach Generating Station	HB1	225.75	Jan-Dec 2013
Redondo Beach Generating Station	RB5	178.87	Jan-Dec 2013, 2014
	RB6	175.00	Jan-Dec 2013, 2014
	RB7	505.96	Jan-Dec 2013, 2015
	RB8	495.90	Jan-Dec 2013, 2014, 2015

Beginning in July 2012, SCE and JPMorgan, on behalf of BECA, began negotiation of a bilateral transaction whereby BECA would resell all of its rights under the Base Agreement to SCE pursuant to a modified "back-to-back" tolling agreement with BECA. A discussion of the substance of the negotiations is provided in Appendix A. The BECA Contract is included as Appendix C.

III. SUMMARY OF BECA CONTRACT

SCE and BECA ultimately agreed to a modified "back-to-back" transaction based on the terms of the Base Agreement. The BECA Contract is intended to provide SCE with the rights and obligations that BECA has under the Base Agreement. SCE will receive energy, capacity, ancillary services, and RA benefits (including all RA attributes such as local RA and the as yet to be determined flexible RA product, to the extent the units can provide them) for a term beginning on October 1, 2013, and ending on May 31, 2018, via a tolling arrangement for the AES 4000 generating units listed in Section II.A above. As part of the transaction, all existing RA agreements between BECA and SCE will be terminated or amended to end prior to October 1, 2013, and replaced with the new BECA Contract.[3]

Additionally, BECA and the AES Subsidiaries are also parties to a May 1, 1998 agreement (the "Capacity Addition Agreement") under which, among other things, BECA has consent rights with respect to new generating capacity in certain portions of the LA Basin constructed by the AES Subsidiaries.[4] Under the BECA Contract, BECA is granting SCE its consent rights under the Capacity Addition Agreement, effective upon final and non-appealable Commission approval of the BECA Contract.

More details about the BECA Contract are included in Appendix A.

IV. BENEFITS OF THE BECA CONTRACT

As discussed below and in Appendix A, the BECA Contract secures dispatch control of critical LA Basin generating facilities for SCE and provides SCE's customers with energy, capacity, ancillary services, and all current and future RA benefits from such facilities at a reasonable price. In addition, there are other unique and substantial benefits of the BECA Contract that warrant its approval by the Commission.

A. Removing Contractual Barriers to Synchronous Condensers at Huntington Beach Units 3 and 4

The ongoing outage at the San Onofre Nuclear Generating Station ("SONGS") has illuminated the critical need for voltage support and electric generation in the Ellis Sub-area of the LA Basin and northern San Diego County. The Huntington Beach Generating Station and, to a lesser extent, the Alamitos Generating Station, provide a significant contribution to meet that local need.

The CAISO has entered into a Reliability Must-Run ("RMR") agreement with AES Huntington Beach, L.L.C. ("AESHB") to convert Huntington Beach Units 3 and 4 into

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3 The terms of SCE's existing unit contingent tolling agreements with RA for the AES 4000 units will end prior to the start of the BECA Contract.

4 The Capacity Agreement is attached as part of the version of the Base Agreement that is publicly available at http://www.cers.water.ca.gov/pdf_files/power_contracts/williams/111902wllmsPPA.pdf.

Public Appendix A

Contract and Valuation Information

CONTRACT AND VALUATION INFORMATION

I. Negotiation of the BECA Contract

As explained in the main portion of this Advice Letter, since obtaining the rights to the AES 4000 as set forth in the Base Agreement, JPMorgan, on behalf of its subsidiary BECA, has participated in SCE's annual All-Source RFOs and, through those solicitations, has resold some of its tolling and RA rights from the AES 4000 to SCE.[1]

The existing volumes, prices, and terms of SCE's unit contingent tolling agreements with RA for AES 4000 units are included in the table below.

Generating Facility	Unit	Contract Capacity (MW)	Price ($/kW-month)	Term
Alamitos Generating Station	AL5	497.97	[redacted]	Jan 2011-Sept 2013
Huntington Beach Generating Station	HB2	225.80	[redacted]	Jan 2012-Sept 2013

The existing volumes, prices, and terms of SCE's RA agreements for AES 4000 units are included in the table below.[2]

Generating Facility	Unit	Contract and RA Capacity (MW)	Jan-Dec 2013	Jan-Dec 2014	Jan-Dec 2015
Alamitos Generating Station	AL1	174.56	[redacted]	[redacted]	
	AL2	175.00	[redacted]	[redacted]	
	AL3	332.18	[redacted]		
	AL4	335.67	[redacted]		
	AL5	497.97			[redacted]
	AL6	495.00	[redacted]	[redacted]	[redacted]
Huntington Beach Generating Station	HB1	225.75	[redacted]		
Redondo Beach Generating Station	RB5	178.87	[redacted]	[redacted]	
	RB6	175.00	[redacted]	[redacted]	
	RB7	505.96	[redacted]		[redacted]
	RB8	495.90	[redacted]	[redacted]	[redacted]

[1] The confidential information in the confidential version of this Appendix is generally highlighted in gray. However, certain confidential information in tables and charts could not be highlighted in gray, but is redacted in the public version of this Appendix.

[2] Prices are in $/kW-month.

[redacted]

[redacted] SCE and BECA ultimately agreed to a modified "back-to-back" transaction based on the terms of the Base Agreement [redacted] The BECA Contract is intended to provide SCE with the rights and obligations that BECA has under the Base Agreement. SCE will receive energy, capacity, ancillary services, and RA benefits (including all RA attributes such as local RA and the as yet to be determined flexible RA product, to the extent the units can provide them) for a term beginning on October 1, 2013, and ending on May 31, 2018,[3] via a tolling arrangement for the covered AES 4000 units. As part of the transaction, all existing RA agreements between BECA and SCE will be terminated or amended to end prior to October 1, 2013, and replaced with the new BECA Contract.[4]

Additionally, under the BECA Contract, BECA is granting SCE its consent rights under the Capacity Addition Agreement, effective upon final and non-appealable Commission approval of the BECA Contract. [redacted]

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3 The original term of the Base Agreement was 15 years with either party having the option to extend the term an additional five years. [redacted]

4 The terms of SCE's existing unit contingent tolling agreements with RA for the AES 4000 units will end prior to the start of the BECA Contract.

[redacted]
Effective upon final and non-appealable Commission approval of the BECA Contract, SCE will obtain BECA's consent rights and will consent to the interconnection and operation of the synchronous condensers. Accordingly, final and non-appealable Commission approval of the BECA Contract will remove the contractual barrier AESHB currently faces and allow it to proceed with the operation of the synchronous condensers. As indicated in the main portion of this Advice Letter, SCE is requesting that the Commission approve this Advice Letter on an expedited basis, by no later than May 9, 2013, in order to allow sufficient time for the synchronous condensers to be operational for the peak summer season, which the CAISO has determined is necessary for local area reliability.

II. Summary of BECA Contract

The BECA Contract is attached as Appendix C. The BECA Contract is not the typical tolling arrangement that SCE enters into. As stated earlier, the BECA Contract is a modified "back-to-back" transaction. In other words, most of the terms regarding operations and expected performance are the same across the agreements. Under the BECA Contract, BECA provides everything it gets from the AES Subsidiaries to SCE. [redacted]

[redacted]

It is important to note that the description above is high level and that the provisions governing this arrangement are very complicated. Thus, ultimately, the contract language is the best source for determining the rights of the parties, and this summary is not a complete description of every possible scenario that could arise under the BECA Contract.

A summary of the major terms and conditions of the BECA Contract is included below.

<table>
<tr><td>Seller</td><td>BECA</td></tr>
<tr><td>Buyer</td><td>SCE</td></tr>
<tr><td>Transaction Overview</td><td>Seller is providing Buyer with its rights under the Base Agreement. Buyer will receive energy, capacity, ancillary services, and all current and future RA benefits from the Units listed below, if provided by the Units.

Buyer and Seller will terminate or amend to end prior to the start of the BECA Contract all existing sales of RA capacity between the Parties effective at the start of the Deal Term.</td></tr>
<tr><td>[redacted]</td><td>[redacted]</td></tr>
<tr><td>Deal Term</td><td>October 1, 2013 through May 31, 2018</td></tr>
<tr><td>Units</td><td>
<table>
<tr><th>Generating Facility</th><th>Unit</th><th>RA Capacity (MW)</th><th>Dependable Capacity (MW)</th></tr>
<tr><td rowspan="6">Alamitos Generating Station</td><td>AL1</td><td>174.56</td><td>175</td></tr>
<tr><td>AL2</td><td>175.00</td><td>175</td></tr>
<tr><td>AL3</td><td>332.18</td><td>320</td></tr>
<tr><td>AL4</td><td>335.67</td><td>320</td></tr>
<tr><td>AL5</td><td>497.97</td><td>480</td></tr>
<tr><td>AL6</td><td>495.00</td><td>480</td></tr>
<tr><td rowspan="2">Huntington Beach Generating Station</td><td>HB1</td><td>225.75</td><td>215</td></tr>
<tr><td>HB2</td><td>225.80</td><td>215</td></tr>
<tr><td rowspan="4">Redondo Beach Generating Station</td><td>RB5</td><td>178.87</td><td>175</td></tr>
<tr><td>RB6</td><td>175.00</td><td>175</td></tr>
<tr><td>RB7</td><td>505.96</td><td>480</td></tr>
<tr><td>RB8</td><td>495.90</td><td>480</td></tr>
<tr><td></td><td>Total</td><td>3817.66</td><td>3,690</td></tr>
</table>
</td></tr>
<tr><td>Dependable Capacity</td><td>Initially 3,690 MW

For each year of the Deal Term, the AES Subsidiaries may adjust each Unit’s Dependable Capacity plus or minus 5% from the initial amount. In other words, adjustments to the Dependable Capacity of each Unit can be made once a year, every year, so long as the Dependable Capacity</td></tr>
</table>

	remains in the plus or minus 5% band of the initial amount.[5]
Toll Product	Tolls will be physical gas (i.e., SCE provides the gas to the Units), with energy delivery at the individual project busbar.
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

5 [redacted]

6 [redacted]

7 [redacted]

	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted] [redacted]
[redacted]	[redacted]

[redacted]	[redacted]
Consent Rights	Upon final and non-appealable Commission approval, Seller grants Buyer its consent rights under Section 2.1(a) of the Capacity Addition Agreement.

III. EVALUATION METHODOLOGY AND RESULTS

A. Evaluation Methodology

SCE's evaluation methodology is summarized in the main portion of this Advice Letter. In general, the quantitative valuation entails forecasting (1) the value of contract benefits, (2) the value of contract costs, and (3) the net value of both (1) and (2). Once all of the valuation elements are calculated, they are discounted to a present value using a 10% discount rate. SCE then subtracts the present value of expected costs from the present value of expected benefits to determine the expected net present value ("NPV") of the offer. NPVs are normalized by dividing them by the number of kW-months of capacity offered to SCE. In addition to quantitative benefits, many contracts also have qualitative benefits that are evaluated separately. The qualitative benefits of the BECA Contract are discussed in the main portion of this Advice Letter.

SCE discusses confidential information related to the quantitative valuation of the BECA Contract below, but does not repeat the discussion of all elements of its evaluation methodology.

1. Contract Benefits

- Energy and Ancillary Service Benefits

As noted in the main portion of this Advice Letter, in valuing energy and ancillary service benefits, SCE uses the economic dispatch principle, wherein a unit is dispatched if its forecasted benefits exceed its costs, i.e., if it is "in the money." ProSym compares the forecast cost of running a unit against energy and ancillary services price forecasts to determine whether a unit is in the money. SCE creates an expansive lookup library of ProSym dispatch results to avoid the need to perform multiple runs for each analysis. [redacted]

SCE then deploys a stochastic Monte Carlo simulation process to generate a large number of gas price and implied market heat rate pairs, using SCE's blended power and gas price curves as the expected case (see below for more details), by

ATTACHMENT 1

Planning Assumptions Update and Scenarios for use in the CPUC Rulemaking R.13-12-010 (The 2014 Long-Term Procurement Plan Proceeding), and the CAISO 2015-16 Transmission Planning Process

REDLINE VERSION

Ruling.[5] Following a similar process of workshops and comments in 2012 and 2013, the CPUC established LTPP planning assumptions for the 2012 and 2014 LTPP that build upon previous planning efforts to further improve the LTPP process.[6] This document refines earlier efforts and furthermore seeks to achieve transparent and consistent assumptions and coordination for resource planning activities across the energy agencies.

2 Guiding Principles

The Guiding Principles[7] for developing assumptions to be used and scenarios to be investigated in the 2014 LTPP Rulemaking:

A. **Assumptions** should take a realistic view of expected achievements from established policies while exploring potential impacts from possible policy changes.

B. **Assumptions** should reflect real-world possibilities, including the stated positions or intentions of market participants.

C. **Scenarios** should be informed by an open and transparent process. An exception is confidential market price data, which may be reasonably submitted with publicly available engineering or market-based price data checked against confidential market price data for accuracy.

D. **Scenarios** should inform the transmission planning process and the analysis of flexible resource requirements to reliably integrate and deliver new resources to loads.[8]

E. **Scenarios** should be designed to form useful policy information, for example tracking greenhouse gas reduction goals, and reliability implications of existing and expected resource procurement policies.

F. **Resource portfolios** should be substantially unique from each other.

G. **Scenarios** should inform bundled procurement plan limits and positions.

H. **Scenarios** should be limited in number based on the policy objectives that need to be understood in the current Long Term Procurement Plan cycle.

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[5] *See* Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, issued December 3, 2012, http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm

[6] Decision Adopting Long-Term Procurement Plans Track 2 Assumptions and Scenarios, D.12-12-010, issued December 20, 2012.

[7] *See* Assigned Commissioner's Ruling on Standardized Planning Assumptions, R.12-03-014, issued June 27, 2012.

[8] Scenarios used by the CAISO Transmission Planning Process must meet the requirements in Section 24.4.6.6 of the CAISO's tariff. Scenarios developed in the LTPP process may inform the development of the CAISO's TPP scenarios to the extent feasible under the CAISO tariff and adopted by that organization.

I. Resource planners including the CPUC, CEC, and CAISO should strive to reach agreement on planning assumptions, and commit **to transparent, consistent, and coordinated planning processes.**

3 Planning Scope: Area & Time Frame

The following assumptions and scenarios are created specifically with regard to the loads served by and the supply resources interconnected to the CAISO-controlled transmission grid and the associated distribution systems. The LTPP planning period is established as twenty years in order to consider the major impacts of infrastructure decisions now under consideration. While detailed planning assumptions are used to create an annual loads and resources assessment in the first period (2014-2024), more generic long-term assumptions are used in the second period (2025-2034), reflecting heightened uncertainties around future conditions[9]. The second period is designed to inform resource choices made today as well as shape policy discussions, and not to make authorizations of need in those years. The CPUC primarily expects technical studies of system and local reliability in 2024 to inform procurement decisions. However, the CPUC does not limit itself to studying 2024 and may also consider technical studies of interim years before 2024. The CAISO's TPP studies target several years within the first ten-year period, including the tenth year for long-term local reliability studies. In the 2014-15 TPP, long-term reliability studies focused on 2024, while the 2015-16 studies will focus on 2025.[10] As such, the staff of the CPUC, CEC, and CAISO focused on developing the most reasonable set of assumptions up to year 2024 for the LTPP and up to 2025 for the TPP. This document supersedes the previous versions of assumptions and scenarios in this proceeding.

[9] The updates incorporated in this document will also inform the 2015-16 TPP studies for the 2015-2025 timeframe.

[10] As stated in an earlier footnote, in the 2015-16 TPP, the CAISO will conduct local capacity requirement analyses for the LA Basin and San Diego local areas, and the Moorpark subarea of the Big Creek/Ventura local area. Full analyses of all local areas occur every two years, on cycles starting on even years.

4 Planning Assumptions

A description of assumptions is provided in this section. All values are reported in the 2014 Scenario Tool, a spreadsheet developed by CPUC staff to quantitatively present the load and resource assumptions for each of the scenarios described in this document.[11]

4.1 Demand-side Assumptions

4.1.1 Base, Incremental, and Managed Forecasts

Demand-side assumptions are either base forecasts or incremental to the demand forecast. Base values, such as the California Energy Demand Forecasts (CED),[12] are independent forecasts without ties to any other forecast. Incremental resource projections, such as Additional Achievable Energy Efficiency[13] (AAEE, formerly known as Incremental Uncommitted Energy Efficiency, or IUEE), are not embedded in the base forecast, but can be used to modify the base forecast to create a net or "managed" forecast. As an example, in the CED, which is treated as a base load forecast, the CEC embeds an amount of energy efficiency representing current codes and standards and established energy efficiency programs. AAEE represents future expected energy and capacity savings from programs not yet established or funded, so AAEE is considered an incremental resource projection. Reducing the base load forecast by the AAEE incremental impacts creates a managed load forecast. Assumptions originating from other state agencies, for example the CED, will not be re-litigated in this proceeding.

4.1.2 Locational Certainty

As California chooses to meet its electricity needs with increasing proportions of demand-side management resources, such as energy efficiency and customer-sited solar photovoltaic (PV) self-generation, it becomes increasingly important to accurately forecast the locations of these demand-side impacts in order to capture the benefits of these resources. Reliability studies in

[11] The 2014 Scenario Tool, version 4 will be posted to the following location: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

[12] The CED: California Energy Demand 2014-2024 Forecast, http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/

[13] The AAEE projections: Estimates of Additional Achievable Energy Savings, Supplement to California Energy Demand 2014-2024 Forecast, http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/Additional_Achievable_Energy_Efficiency/

transmission-constrained local areas depend on these demand-side resources providing capacity value at least within the electrical areas forecasted, and preferably at specific transmission-level busbar or substation locations if they are to offset local capacity requirements. Historically, demand-side resource projections lacked the locational certainty needed to contribute to local reliability. However, the current California Energy Demand set of forecasts, with its embedded demand-side resources and incremental AAEE projections, is moving in the direction of greater locational certainty by providing impacts at the climate zone level. The CEC defines 15 climate zones in California.[14] Efforts are underway to further refine the locational certainty of all demand-side resources so that their benefit as substitutes for conventional generation can be realized in future planning cycles.

4.1.3 Load

The CEC's 2013 Integrated Energy Policy Report (IEPR) California Energy Demand (CED) forecasts serve as the source for the "managed demand forecast," consisting of a base load forecast coupled with several alternative Additional Achievable Energy Efficiency (AAEE) projections (see subsection on Energy Efficiency below). The CED base forecasts include three load cases, "Low", "Mid", and "High", each factoring in variations on economic and demographic growth, retail electricity rates, fuel prices, and other elements. Each load case also has peak demand weather variants, for example, 1-in-2 weather year and 1-in-10 weather year. The 2014 LTPP Scenarios incorporate the "Mid" and "High" load cases.

The 2013 IEPR CED forecasts account for transportation electrification given existing state policies. Development of policies that drive higher electrification growth is underway, and may include increased penetration of electric vehicles (EVs) across all vehicle types, and accelerated rail electrification. As the impacts of such policies become more certain, future planning assumptions will consider accounting for such policies by adjusting the base load forecast (e.g., changes in load shapes and higher annual energy consumption).

The CEC adopted the CED base forecasts on December 11, 2013, and published final versions in spreadsheet format.[15] The 2013 IEPR final report, published on January 23, 2013,[16] based on the IEPR record and in consultation with the CPUC and the CAISO, recommends that the Mid load case (and associated peak demand weather variants) of the CED base forecasts shall be used for long-term infrastructure planning activities at the CPUC, CEC, and CAISO.

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[14] See p. 51 of http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

[15] See spreadsheets at http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/

[16] See pp. 127-130 of http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf

The CEC staff made its 2014 IEPR Update CED forecasts available in December 2014, and the CEC adopted a slightly revised version in January 2015. Therefore, the 2015-16 CAISO TPP is expected to use the 2014 IEPR Update CED forecasts (Mid load case) as its source for the "base demand forecast".[17] Adjustments to this base forecast, such as subtracting AAEE, produce a "managed demand forecast" that incorporates demand-side policy goals not included within the CEC's base demand forecast.

4.1.4 Energy Efficiency

Energy efficiency forecasts shall be developed from the CEC's 2013 IEPR CED base forecasts and its supplemental Additional Achievable Energy Efficiency (AAEE) projections. Each load case of the CED base forecasts contains an embedded EE component that will be paired with an AAEE projection scenario representing additional savings. CEC staff, with input from the Demand Analysis Working Group and in consultation with CPUC staff and CAISO staff, developed the AAEE projections from the CPUC's 2013 California Energy Efficiency Potential and Goals Study.[18] The AAEE projections include five savings scenarios, "Low", "Low-Mid", "Mid", "High-Mid", and "High". In general, the lowest savings scenario includes only the EE savings most certain to materialize while the highest savings scenario includes all EE potential including aspirational goals (e.g. emerging technologies). Depending on the type of planning study, finer granularity of EE savings projections may be required. Some planning study types may utilize EE savings projections allocated at the transmission-level busbar, and/or daily and seasonal load-shape EE savings projections. Such studies may need to account for uncertainties regarding busbar location or load-shape impacts. In all studies, transmission and distribution loss-avoidance effects shall be accounted for.

Like the CED base forecasts, the CEC adopted the AAEE projection scenarios on December 11, 2013, and published final versions in spreadsheet format.[19] During 2013, the CEC, CPUC and CAISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in these planning and procurement processes. To that end, the 2013 IEPR final report, published on January 23, 2013,[20] based on the IEPR record and in

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[17] The CPUC expects to continue to use the 2013 IEPR CED forecasts for consistency throughout the two year 2014 LTPP cycle

[18] Attached to the R.13-11-005 Assigned Commissioner's Ruling Amending Scoping Memorandum, and providing guidance on energy savings goals for program year 2015 http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=88661908

[19] http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/Additional_Achievable_Energy_Efficiency/

[20] See pp. 127-130 of http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf

consultation with the CPUC and the CAISO, recommends using the Mid AAEE scenario for system-wide and flexibility studies for the CPUC 2014 LTPP and CAISO 2014-15 TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low-Mid AAEE scenario for local studies is more prudent at this time.

For the purposes of calculating a statewide renewable net short to develop Renewable Portfolio Standard (RPS) portfolios, that calculation must also account for energy load reductions from incremental EE for all California Publicly Owned Utilities (POUs). That amount of incremental EE is the sum of the projections of each POU's incremental (uncommitted) EE reported by the POU on the CEC's S-2 supply forms.[21] The CEC projects 3,420 GWh of POU incremental EE savings in 2022 and recommends the same assumption in 2024. This number is used to calculate the statewide renewable net short in 2024.

The 2014 IEPR Update CED forecasts were made available in December 2014 and adopted by the CEC in January 2015. The 2014 IEPR Update aggregate projections of AAEE were not substantively changed from the 2013 IEPR. However, they have been scaled down slightly to account for the passage of time and the inclusion of more years of historical data in the base demand forecast. In addition, CEC staff intends to provide an updated allocation of EE savings projections down to the transmission level busbar to the CAISO for use in the 2015-16 TPP. As described earlier in this section, the 2015-16 TPP will continue to use the Low-Mid AAEE projection in local reliability studies.

4.1.5 Solar Photovoltaics

The CED forecasts embed the impacts of initiatives such as the California Solar Initiative, as well as the effects of retail rates and programs such as Net Energy Metering. As such, the default projection for behind-the-meter solar PV assumes no change from what the CED forecasts embed. Besides the default projection, planning scenarios may model a low or high projection of behind-the-meter solar PV ***incremental*** to the default projection. The low incremental projection is created by subtracting the self-generation PV projection embedded in the CED "Mid" load case (mid PV projection) from the self-generation PV projection embedded in the CED "Low" load case (high PV projection). The high incremental projection is created by subtracting the self-generation PV projection embedded in the CED "Mid" load case from the projection in the CPUC's study on the ratepayer impacts of Net Energy Metering (NEM)

[21] http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2013/ See each POU's Uncommitted Energy Efficiency plans in the spreadsheet section "Generation/Production" on line item 3.

prepared by Energy and Environmental Economics (E3).[22] The NEM study result projects total cumulative behind-the-meter PV to reach 5,573 MW of installed capacity in 2020,[23] and CPUC staff linearly extrapolates this to 7,783 MW of installed capacity in 2024.

Although behind-the-meter PV is generally regarded as a demand-side resource, both the CED embedded PV and any incremental amounts will be modeled as supply resources, and modelers will adjust upward the load forecast as needed when accounting for CED embedded self-generation on the supply-side. This maintains consistency with modeling practice that treats these resources as non-dispatchable generators with both capacity value and an annual production profile. Transmission and distribution loss-avoidance effects shall be accounted for. Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios, and to model capacity value at peak (peak impact factor) and annual energy production (capacity factor) using values implied by the CED "Mid" load case embedded self-generation PV projection for each of the three major IOUs. The table below summarizes by IOU the implied peak impact factor and capacity factor.

Table 1: Small Solar PV Operational Attributes

Variable	PG&E	SCE	SDG&E	Average of all 3 IOUs
Peak impact factor	0.47	0.47	0.47	0.47
Capacity factor	0.18	0.19	0.20	0.19

4.1.6 Combined Heat and Power

The CED forecasts embed the impacts of initiatives such as the Self-Generation Incentive Program. As such, the default projection for behind-the-meter combined heat and power (CHP) assumes no change from what the CED forecasts embed. Besides the default projection, planning scenarios may model a low or high projection of behind-the-meter CHP ***incremental*** to the default projection. ICF International conducted a policy analysis of CHP resources through 2030 and produced a report published in July 2012.[24] The low incremental projection is based on a CEC analysis of the "Base" projection of on-site generation from the ICF report. The high incremental projection is based on a CEC analysis of the "High" projection of on-site generation

[22] http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm

[23] See the "Forecast" Tab in the E3 NEM Summary Public Model located at: http://www.cpuc.ca.gov/NR/rdonlyres/AD52FE7A-E283-4AB8-BCB2-87DF56D7443B/0/E3NEMSummaryTool.xlsm

[24] *See* Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

from the ICF report.[25] Note that since the projections in the ICF report are statewide, these numbers are disaggregated to planning areas for the three major IOUs using ratios derived from the CEC analysis of the "Base" and "High" projections of on-site generation from the ICF report. This results in CAISO area 2024 incremental installed capacity projections of 955 MW in the low case, and 2,405 MW in the high case.

Similar to behind-the-meter PV, behind-the-meter CHP is generally regarded as a demand-side resource. As such, CHP embedded in the CED forecast, in addition to any incremental CHP amount, will be modeled as supply resources. Modelers will adjust the load forecast upward, as needed, when accounting for CED forecast embedded self-generation on the supply-side. This maintains consistency with modeling practice that treats these resources as non-dispatchable generators with both capacity value and an annual production profile. Transmission and distribution loss-avoidance effects shall be accounted for. Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios, and to model capacity value at peak (peak impact factor) as 0.70 of installed capacity and annual energy production using a 0.80 capacity factor.

4.1.7 Demand Response

The CED forecasts embed the impacts of load-modifying[26] demand response (DR) programs, in other words, those impacts are treated on the demand-side. These programs are generally non-event-based and/or tariff-based and include TOU rates, Permanent Load Shifting, and Real Time Pricing. Supply-side DR programs, which are generally event-based, price-responsive and reliability programs, are treated as supply resources.

There may be other effects that supply additional DR impacts, for example, a higher EV penetration could lead to charging models that can provide load shifting and frequency regulation by managing the charging times of an aggregate group of EVs. These speculative impacts are not accounted for at this time. Another expected future DR impact may come from defaulting residential customers to TOU rates. These impacts may be explored in the next major CEC IEPR planning cycle.

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[25] Straight-line interpolation for intervening years between the "Base" case and "High" case target years identified in the ICF report

[26] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on "load-modifying" and "supply-side" DR programs.

4.1.8 Energy Storage

Energy storage units shall be modeled as supply-side resources; therefore this document describes the planning assumptions for distribution-connected and customer-side storage, as well as transmission-connected storage, within the Supply-side Assumptions section.

4.1.9 Avoided Transmission and Distribution Losses

Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. The factors are multiplied by demand-side resource projections to determine the avoided generation replaced by the presence of the demand-side resource.

Table 2: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

4.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications for existing or future contracts. To the extent a specific projected resource is not available; the analysis assumes an electrically equivalent resource will be available.

All supply-side resources should be categorized either as within a specific local area, as a generic system resource, or as out-of-state. Resources should be accounted for in terms of their most current net qualifying capacity (NQC). For purposes of constructing simple annual load and resource tables, August NQC values will be used. In the absence of a NQC, a resource's expected NQC should be based on its expected installed capacity adjusted for the peak impact value of that technology type. To the extent that NQC accounting methodologies change in the future, those changes should be reflected in LTPPs subsequent to the current LTPP. For variable resources, methods that can forecast production based on a variety of conditions are preferred to utilizing single point or year assumptions. For example, 8760 hour generation profiles for variable resources are used in production simulation model analyses. These profiles may also be used in CAISO TPP studies to determine output levels of these resources corresponding to the load levels (peak, off-peak, partial peak, and light load base cases) of the applicable studies. The Effective Load Carrying Capability (ELCC) method of assigning capacity value to wind and solar resources is expected to become available for the next cycle of developing planning assumptions. At this time, no degradation of resource production over time is accounted for in these planning assumptions.

4.2.1 Existing Resources

The capacities of existing resources shall be the monthly NQC values found in the 2014 Resource Adequacy compliance year NQC list.[27] The CAISO and CPUC both publish these lists annually on their respective websites.

4.2.2 Conventional Additions

The default values for conventional resource additions 50 MW or larger derive from the list of power plant siting cases maintained on the CEC website.[28] The default values for conventional resource additions smaller than 50 MW derive from other databases maintained by the CEC. The CEC updates these lists several times per year. A power plant project shall be counted if it (1) has a contract, (2) has been permitted, and (3) has begun construction. A power plant project that does not meet these criteria may be counted if the staff of the agency with permitting jurisdiction expects the project to come online within the planning horizon.[29]

4.2.3 Combined Heat and Power

Resources identified here export electricity to the grid. The Demand-side Assumptions section discusses resources that provide on-site energy. The default projection for exporting CHP assumes no net growth. Planning scenarios that model a higher penetration of exporting CHP shall add either a low or a high incremental projection of growth. ICF International conducted a policy analysis of CHP resources through 2030 and produced a report in July 2012.[30] The low

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[27] *See* Resource Adequacy Compliance Materials at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

[28] http://www.energy.ca.gov/sitingcases/all_projects.html

[29] The Oakley power plant project was approved by the CPUC but recently annulled by the California Court of Appeal: http://www.courts.ca.gov/opinions/documents/A138701.PDF Therefore, Oakley will not be assumed as a conventional resource addition. During the second year of the LTPP cycle, CPUC staff expects to facilitate additional studies with varying additional resource options to determine the best way to fill any need found from studies conducted during the first year of the LTPP cycle. At that time, there may be an opportunity to explore the efficacy of the Oakley power plant in meeting identified needs.

[30] See Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment – Consultant Report at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

incremental projection is based on a CEC analysis of the “Base” projection of exporting CHP from the ICF report. The high incremental projection is based on a CEC analysis of the “High” projection of exporting CHP from the ICF report.[31] Note that since the projections in the ICF report are statewide projections, these numbers are adjusted downward by a factor of 0.8, approximately the CAISO area to statewide load ratio. This results in CAISO area 2024 installed capacity projections of 164 MW in the low case, and 1,855 MW in the high case.

Absent more specific locational and technology type information for a resource projection, the default shall be to allocate aggregate resource projections to substations on the basis of peak load ratios and to model capacity value at peak (peak impact factor) as 0.70 of installed capacity. These resources are assumed to be non-dispatchable by the CAISO.

4.2.4 Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target[32] of 1,325 MW installed capacity of new energy storage units within the CAISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs. Storage operational after January 1, 2010 and no later than December 31, 2024 shall count towards the procurement target. The default planning assumption for new storage capacity shall account for a conservative expected contribution to grid services and reliability from the storage procurement target in D.13-10-040. No further growth in new storage capacity is assumed post 2024.

<u>Assumptions about storage attributes and capabilities</u>

While all storage can provide energy services, that is, storage can charge during periods of low energy prices and discharge during periods of high energy prices, their ability to provide capacity and flexibility (load-following, ancillary services, etc.) depends on their visibility and controllability by the CAISO. Transmission-connected storage will likely interconnect to the system near transmission substations and be visible and controllable by the CAISO. Therefore, all of the 700 MW of new transmission-connected storage described above is assumed to provide capacity and flexibility as a default.

The ability of distribution-connected storage to provide capacity and flexibility carries significant uncertainty, in part because this technology is new to the market, and in part

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[31] Straight-line interpolation for intervening years between the “Base” case and “High” case target years identified in the ICF report

[32] The Decision specifies that resources must be online by 2024 so in the planning assumptions, target amounts are reached in 2024.

because current policy and the CAISO market does not fully support the participation of distribution-connected resources. Therefore, only 50% of the 425 MW of new distribution-connected storage described above is assumed to provide capacity and flexibility as a default. This acknowledges that greater than zero percent but less than 100% of these resources are expected to provide such services.

The ability of customer-side storage to provide capacity and flexibility carries even higher uncertainty. Not only is the market new, but customer-side storage will likely be non-dispatchable by either the CAISO or the IOUs (absent significant policy and market changes) and it is unclear how much of customer-side storage will charge from the grid or on-site generation, and according to what schedule. Therefore, none of the 200 MW of new customer-side storage described above is assumed to provide capacity and flexibility as a default.

A limiting factor to the ability of storage to provide capacity during peak demand hours is the duration of sustained output. The CPUC factors in a resource's ability to sustain output for at least four hours when calculating NQC for Resource Adequacy purposes.[33] Therefore, storage resources that only have a depth of two hours should have their capacity value derated by half (50%) for purposes of power flow reliability studies. This accounts for the inability of such resources to sustain full output during the duration of system peak hours. Capacity values in Table 3 below reflect this adjustment.

Note that although there are limits on the amount of storage procurement assumed to provide capacity and flexibility as described above, all 1,325 MWs can provide energy services and will be modeled as such in studies involving production cost simulations. The capacity limitations described above applies to power-flow type studies conducted in the CAISO's TPP. The table below describes the assumptions that shall be used for the technical characteristics and accounting of the three classes of storage described by D.13-10-040.

[33] See page 32 of http://www.cpuc.ca.gov/NR/rdonlyres/C61CB838-E9BB-4CE2-AEB3-63DB955E2EF8/0/RAWorkshopReport2004.doc

Table 3: Storage Operational Attributes

Values are MW in 2024	Transmission-connected	Distribution-connected	Customer- side
Total Installed Capacity	700	425	200
Amount providing capacity in power flow studies	560 *	170 *	0
Amount providing flexibility	700	212.5	0
Amount with 2 hours of storage	280	170	100
Amount with 4 hours of storage	256 ^	170	100
Amount with 6 hours of storage	124 ^	85	0
Charging rate: If a unit is discharged and charged at the same power level, assume it takes 1.2 times as long to charge as it does to discharge. Example: 50 MW unit with 2 hours of storage. If the unit is charged at 50 MW, it will take 2.4 hours to charge. If the same unit is charged at 25 MW, it will take 4.8 hours to charge.			

***** This reflects a 50 % derating of capacity value of 2 hour storage due to not being able to sustain maximum output for 4 hours per Resource Adequacy accounting rules.
^ This amount was adjusted down to reflect the assumption that the 40 MW Lake Hodges storage project satisfies the storage target for a portion of SDG&E's share of the target.

In the CAISO's TPP Base local area reliability studies, locations for this new storage capacity must be assumed. It is reasonable to assume that cost-effectiveness requirements for new storage capacity will lead to siting at the most effective locations to contribute to local area reliability. As the CAISO's technical studies in the 2014-15 TPP identify transmission constraints in the local areas, the CAISO will identify the effective busses for mitigating those constraints. The storage amounts providing capacity and flexibility identified in the table above will be distributed amongst effective busses within the local areas and modeled. These bus locations are potential development sites for storage and shall inform the actual procurement to meet the storage procurement target.

All energy storage described here is exclusive and incremental to any similar technologies that are accounted for as non-dispatchable DR (e.g. Permanent Load Shifting) embedded within the CEC's CED forecasts.

<u>Adjustments due to actual and expected storage projects</u>

The 50 MW of storage that D.13-02-015 ordered SCE to procure and the 25 MW of storage that D.14-03-004 ordered SDG&E to procure are assumed to count towards the D.13-10-040 storage procurement target and shall not be double counted. To the extent pending applications to fill procurement authorizations D.13-02-015 and D.14-03-004 include storage beyond the minimum requirements ordered in the decisions, such storage projects are also assumed to count towards the storage procurement target and shall not be double counted. Table 3 above does not include any adjustment to reflect storage procurement resulting from D.13-02-015 and D.14-03-004. See the discussion on pending applications in section 4.2.13 for further details.

The Lake Hodges storage project in the San Diego area counts as an existing resource within the Scenario Tool. This project is assumed to satisfy a portion of SDG&E's share of the D.13-10-040 storage procurement target and Table 3 above reflects this. Specifically, Lake Hodges is a 40 MW project and is assumed to satisfy all of SDG&E's share of 6-hour transmission-connected storage target (16 MW target minus 16 MW from Lake Hodges) and most of SDG&E's share of 4-hour transmission-connected storage target (32 MW target minus the remaining 24 MW from Lake Hodges).

<u>Alternative storage assumptions</u>

The default planning assumptions accounting for the storage procurement target are admittedly conservative. For example, the assumption that half of distribution-connected storage and all of customer-side storage does not provide capacity or flexibility probably undercounts their value. The intention is to model the grid conservatively to start with in order to reveal potential reliability needs. Any revealed reliability needs will be used to inform how the storage procurement target actually gets implemented. To enable this, during the second year of the LTPP cycle, CPUC staff expects to facilitate additional flexibility studies with varying additional resource options to determine the best way to fill any flexibility need found from studies conducted during the first year of the LTPP cycle. If there is a need, CPUC staff may explore two additional resource options for storage in LTPP flexibility studies:

1. In addition to the default planning assumptions for new storage, add one or two new large-pumped hydro storage units, the exact MW amount depends on what the revealed need is. Note that according to D.13-10-040, the maximum size of pumped storage projects that count towards storage procurement target is 50 MW. Therefore if studies demonstrate that this additional resource option is the best way to fill any need, the LTPP proceeding will consider pumped storage projects larger than 50 MW in general solicitations for new capacity conducted by utilities.

2. In addition to the default planning assumptions for new storage, assume policy and market changes that enable a more complete contribution to grid services and reliability

from new distribution-connected and customer-side storage. Additional storage beyond the storage procurement target may be assumed depending on what the revealed need is.

4.2.5 Demand Response

Demand response, or DR, (generally event-based price-responsive and reliability programs) that can be bid into CAISO market shall be accounted for as a supply-side resource[35]. Transmission and distribution loss-avoidance effects shall be accounted for. The most recent Load Impact reports[36] filed with the CPUC serve as the basis for DR planning assumptions. The Load Impact reports are published annually on April 1. In all types of system and local area resource planning studies, DR capacity shall be counted using the 1-in-2 weather year ex-ante forecast of monthly load impact, portfolio-adjusted. This is consistent with the capacity value of DR for Resource Adequacy. For the purpose of building load and resource tables, DR capacity shall be counted using the 1-in-2 weather year condition ex-ante forecast of August load impact, portfolio-adjusted. For the purpose of building detailed profiles of DR load impact in system and local area planning models, DR is assumed available at times of system stress, subject to program operating constraints but not limited to operating hours specified in Resource Adequacy accounting rules. Program operating constraints are obtained from the utilities' Load Impact reports and tariffs for each program.[37] The ex-ante load impacts for the operating hours specified in Resource Adequacy accounting rules, by program, are found in the Load Impact reports. For modeling purposes, programs with operating hours beyond hour ending 18 shall be triggered at $600/MWh and all other programs shall be triggered at $1000/MWh.

In the CAISO's TPP Base local area reliability studies, only capacity from DR programs that can be relied upon to mitigate "first contingencies", as described in the 2012 LTPP Track 4 planning

[35] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on "load-modifying" and "supply-side" DR programs.

[36] To access IOU Load Impact reports, please see:
PG&E: https://www.pge.com/regulation/DemandResponseOIR/Other-Docs/PGE/2013/DemandResponseOIR_Other-Doc_PGE_20130402_269621.pdf
SCE: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/62A8F5E44C447F0688257B410052EC7B/$FILE/R.07-01-041_DR+OIR-SCE+DR+Portfolio+Summary+2012+-+Final.pdf
SDG&E: http://www.sdge.com/regulatory-filing/742/rulemaking-regarding-policies-and-protocols-demand-response-load-impact

[37] To access IOU demand response tariffs, please see:
PG&E: http://www.pge.com/en/mybusiness/save/energymanagement/index.page
SCE: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response/
SDG&E: http://www.sdge.com/save-money/demand-response/overview

assumptions[38], are counted. DR that can be relied upon to mitigate first contingencies in local reliability studies participates in, and is dispatched from, the CAISO market in sufficiently less time than 30 minutes[39] from when it is called upon.

There is uncertainty as to what amount of DR can be projected to meet this criteria within the TPP planning horizon given that few current programs meet this criteria and the current DR Rulemaking R.13-09-011 expects to restructure DR programs to better meet CAISO operational needs and has already produced two major policy decisions towards that goal.[40] The rulemaking is expected to issue additional decisions that enable demand response to be more useful for grid needs, but CAISO has several tasks it must complete in order to make integration of DR possible.

The 2012 LTPP Track 4 planning assumptions estimated that approximately 200 MW of DR would be available to mitigate first contingencies within the combined LA Basin and San Diego local reliability areas by 2022. The 2014 LTPP planning assumptions, however, estimates that approximately 1,100 MW would be available to mitigate first contingencies within the combined LA Basin and San Diego local reliability areas by 2024. Staff developed this latter estimate by screening DR projections in the Load Impact reports for programs that deliver load reductions in 30 minutes or less from customer notification. The table below identifies for each IOU the programs and capacities that meet this criteria.

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[38] See Attachment A of Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge in R.12-03-014, May 21, 2013, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K202/65202525.PDF

[39] The 30 minute requirement is based on meeting NERC Standard TOP-004-02. Meeting this requirement implies that programs may need to respond in 20 minutes, from customer notification to load reduction, in order to allow for other transmission operator activities in dealing with a contingency event.

[40] Commission Decision 14-03-026 approved the bifurcation of DR programs into two categories: Supply DR (DR that is integrated into CAISO markets and dispatched when and where needed) and Load-Modifying DR (DR that is not integrated into CAISO markets and used to modify the demand forecast). Decision 14-12-024 clarified that complete bifurcation will occur by the beginning of 2018.

Table 4: DR Capacity in Local Area Reliability Studies

"First Contingency" DR Program MW in 2024 using 1-in-2 weather year ex ante impacts	PG&E	SCE	SDG&E
Base Interruptible	287	627	1
Agricultural Pumping Interruptible	n/a	69	n/a
AC Cycling Residential	82	298	12
AC Cycling Non-Residential	1	76	3

Given the uncertainty as to what amount of DR can be relied upon for mitigating first contingencies, the CAISO's 2014-15 TPP Base local area reliability studies examined two scenarios, one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions, shown above. Staff expects the same two scenarios to be examined in the 2015-16 TPP, except that the latter scenario should be updated to be consistent with the latest Load Impact reports filed with the CPUC on April 1, 2014 under R.13-09-011.

To the extent technical studies require estimates of DR capacity at individual transmission-level busbars, DR capacity will be allocated to busbar using the method defined in D.12-12-010, or specific busbar allocations provided by the IOUs. For the 2014-15 TPP, the DR amounts in Table 4 were the basis for busbar allocations provided from the IOUs to the CAISO. In November 2014, the IOUs updated the busbar allocations to be consistent with the latest available Load Impact reports (April 1, 2014). CPUC staff expects the IOUs to provide these updated busbar allocations to the CAISO for use in the 2015-16 TPP. CPUC staff submitted comments identifying the updated busbar allocations in response to the CAISO's request for input on demand response assumptions for the CAISO's 2015-16 Unified Planning Assumptions.[41]

The default planning assumptions accounting for DR capacity are admittedly conservative given CPUC expectations to restructure programs and expand capacity in the DR Rulemaking R.13-09-011. However, rather than speculate what the outcome of the DR Rulemaking might be, the default planning assumptions presume the continuation of the utilities' existing DR programs. The intention is to model the grid conservatively to start with in order to reveal potential reliability needs. Any revealed reliability needs will be used to inform new DR program

[41] Comments were submitted via this CAISO Market Notice: http://www.caiso.com/Documents/StakeholderInputfor2015-2016UnifiedPlanningAssumptions.htm

development/procurement. To enable this, during the second year of the LTPP cycle, CPUC staff expects to facilitate additional flexibility studies with varying additional resource options to determine the best way to fill any flexibility need found from studies conducted during the first year of the LTPP cycle. If there is a need, CPUC staff may explore an additional resource option in LTPP flexibility studies that expands DR capacity such that the total DR capacity is equal to 5% of the forecasted managed 1-in-2 weather year system peak demand by 2021, and reaches 10% of the forecasted managed 1-in-2 weather year system peak demand by 2030. The expanded DR capacity shall be assumed available to hour ending 21, triggered at $600/MWh, and use limited to 20 hours per month. These parameters may be adjusted depending on the revealed need.

4.2.6 RPS Portfolios

Overview

The forecast of renewable resources is developed using the Renewable Portfolio Standard (RPS) Calculator. The RPS Calculator uses public data to develop portfolios of renewable resources to use for planning studies. Since a large portion of the cost associated with renewables is tied to the cost of transmission capacity needed to deliver the power to market, the RPS Calculator optimizes existing transmission and, when necessary, optimizes the use of minor upgrades to existing transmission lines as well as the use of new transmission lines. As such, when two similar resources are incorporated into the RPS Calculator, it selects the resource with access to current transmission capacity over the resource that requires new transmission capacity, thereby minimizing additional transmission cost. The RPS Calculator also incorporates four policy priority metrics: permitting (i.e. quickest on-line time), lowest cost, least environmentally harmful and commercial interest. The weight applied to each metric, in addition to the overall renewable net short (RNS) need, impacts the make-up of a given portfolio. The portfolios created for the 2014-2015 TPP and LTPP reflect the application of a 70% weight to the Commercial Interest score and a 10% weight to the Environmental, Permitting, and Cost scores.

CPUC & CEC Collaboration

CPUC and CEC staff collaboratively developed the RPS portfolios, with CEC staff providing to CPUC staff its most recent IEPR CED retail sales forecast, demand side management assumptions, environmental scores, and online renewable generation, which CPUC staff uses to, among other things, calculate each portfolio's RNS. Once the RPS portfolios are created and vetted via a public stakeholder process, the CPUC and CEC jointly submit the portfolios to the CAISO for incorporation into the CAISO's Transmission Planning Process (TPP) studies. The CAISO's transmission modeling, which is more detailed than the modeling performed by RPS

JP Morgan Ventures Energy Corporation (J

141 FERC ¶ 61,131
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

J.P. Morgan Ventures Energy Corporation   Docket No. EL12-103-000

ORDER SUSPENDING MARKET-BASED RATE AUTHORITY

(Issued November 14, 2012)

1. On September 20, 2012, the Commission issued an order directing J.P. Morgan Ventures Energy Corporation (JP Morgan) to show cause why its authorization to sell electric energy, capacity, and ancillary services at market-based rates should not be suspended.[1] As discussed below, we find that the statements identified in the Show Cause Order constitute violations of section 35.41(b) of the Commission's regulations.[2] Consequently, pursuant to section 206 of the Federal Power Act (FPA), we will suspend JP Morgan's market-based rate authority for a period of six months, to become effective on April 1, 2013.[3]

I. <u>Background</u>

2. In 2005, the Commission authorized JP Morgan to sell electric energy, capacity, and ancillary services at market-based rates in several regions, including the market administered by the California Independent System Operator Corporation (CAISO).[4]

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[1] *J.P. Morgan Ventures Energy Corp.*, 140 FERC ¶ 61,227 (2012) (Show Cause Order).

[2] 18 C.F.R. § 35.41(b) (2012) "*Communications*. A Seller must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences."

[3] 16 U.S.C. § 824e (2006).

[4] *J.P. Morgan Ventures Energy Corp.*, 112 FERC ¶ 61,322 (2005).

JP Morgan continues to be an active participant in the CAISO market, and is therefore subject to the terms and conditions of CAISO's Open Access Transmission Tariff (Tariff or OATT).

3. Section 11.1 of Appendix P of CAISO's Tariff requires CAISO's Department of Market Monitoring (DMM) to refer to the Commission all instances in which the DMM has reason to believe that a Market Violation[5] has occurred and to immediately terminate all independent actions related to the alleged violation following a referral.[6] Section 11.5 of Appendix P of the Tariff similarly prohibits the DMM from undertaking "any investigative steps regarding the referral except at the express direction of FERC or FERC Staff."[7]

4. On March 25, 2011, CAISO sent a data request to JP Morgan regarding its bidding activities in the CAISO market.[8] In March of 2011, CAISO also orally informed JP Morgan that CAISO intended to refer the matter to the Commission's Office of Enforcement.[9] JP Morgan submitted responses to CAISO's March 25 request on April 11, 19, and 27, 2011.[10] In light of those responses, CAISO sent an amended data

[5] The Tariff defines a "Market Violation" as "A CAISO Tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies." CAISO, eTariff, FERC Electric Tariff, App. A (0.0.0).

[6] CAISO, eTariff, FERC Electric Tariff, App. P, § 11.1 (3.0.0) (section 11.1) (". . . Once DMM has obtained sufficient credible information to warrant referral to FERC, DMM shall immediately refer the matter to FERC and desist from independent action related to the alleged Market Violation. DMM may, however, continue to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. DMM shall respond to requests from FERC for any additional information in connection with the alleged Market Violation it has referred.").

[7] CAISO, eTariff, FERC Electric Tariff, App. P, § 11.5 (section 11.5) ("Following a referral to FERC, DMM is committed to notify and inform FERC of any information that DMM learns of that may be related to the referral but DMM shall not undertake any investigative steps regarding the referral except at the express direction of FERC or FERC Staff.").

[8] *See* JP Morgan Response to Show Cause Order at Att. 2 (letter from the DMM to JP Morgan's outside counsel).

[9] *See* JP Morgan Complaint, Docket No. EL12-70-000, at 5 (filed May 21, 2012) (May 21, 2012 Complaint).

[10] *See* JP Morgan Response to Show Cause Order at Att. 2 (letter from the DMM to JP Morgan's outside counsel).

request on May 4, 2011 that requested information responsive to five different areas of inquiry.[11] CAISO identified these separate requests for information as Request No. 1, Request No. 2, Request No. 3, Request No. 4, and Request No. 5. The May 4 data request required JP Morgan to respond by May 18, 2011.[12]

5. In a May 18, 2011 letter to the DMM, JP Morgan's outside counsel cited the "post-referral bar" in section 11.1 of Appendix P of CAISO's Tariff and argued that "the DMM should refer the matter to FERC and stop its independent action."[13]

6. On May 20, 2011, CAISO officially referred JP Morgan's bidding activities to the Office of Enforcement for further investigation.[14]

7. In a June 13, 2011 letter to the DMM, JP Morgan's outside counsel provided certain spreadsheets and stated JP Morgan's belief that "the DMM does not have the authority to seek the [spreadsheets] and should refer the matter to FERC and stop its independent action."[15]

8. In a June 21, 2011 email, the DMM forwarded to JP Morgan's outside counsel the official referral of JP Morgan's bidding activities sent to the Director of the Office of Enforcement on May 20, 2011.[16]

9. In a June 24, 2011, 9:45 AM email to JP Morgan's outside counsel, with the Subject line: "Data requests to JP Morgan from California MMU," staff from the Office of Enforcement wrote:

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[11] *Id*.

[12] *Id.*

[13] *See* JP Morgan Response to Show Cause Order at Att. 3 (letter from JP Morgan's outside counsel to the DMM).

[14] *See* JP Morgan Response to Show Cause Order at Att. 7. CAISO also referred more of JP Morgan's bidding activities in 2010 to the Office of Enforcement in June 2011.

[15] JP Morgan Response to Show Cause Order at Att. 5 (letter from JP Morgan's outside counsel to the DMM).

[16] JP Morgan Response to Show Cause Order at Att. 7 (letter from the DMM to JP Morgan's outside counsel).

> This will confirm that Commission staff has expressly directed the California ISO Market Monitor to continue to seek full and complete responses from JP Morgan to the data requests or other inquiries that the Market Monitor directed to JP Morgan through June 20, 2011.[17]

JP Morgan's outside counsel responded to this email at 11:25 AM: "Thank you."[18]

10. In a July 28, 2011, 12:31 PM email to JP Morgan's outside counsel, with the Subject line: "FW: Data requests to JP Morgan from California MMU," staff from the Office of Enforcement wrote, "I hereby confirm that FERC OE has expressly directed the CAISO MMU to analyze those materials to assist us in our work."[19] JP Morgan's outside counsel responded to this email at 12:49 PM: "Thank you."[20]

11. In a September 27, 2011 letter to JP Morgan, CAISO informed JP Morgan of the results of the CAISO's review of potential violations of the Investigation Information requirements as described in CAISO Tariff Section 37.6.2.[21] CAISO's review determined that JP Morgan had failed to timely provide full responses to Request No. 4 and Request No. 5 of the May 4, 2011 data requests.[22] CAISO's notice indicated that JP Morgan had 30 days to respond to the letter before CAISO determined whether sanctions were required by the CAISO Tariff.[23]

12. Meanwhile, on October 15, 2011, staff from the Office of Enforcement sent an email to JP Morgan's deputy general counsel (and copying JP Morgan's outside counsel) asking if the deputy general counsel could provide the DMM with certain materials that outside counsel still had not provided in response to the DMM's May 4 data request and

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[17] JP Morgan Response to Show Cause Order at Att. 9 (letter from Office of Enforcement staff to JP Morgan's outside counsel).

[18] *See Submission By Office of Enforcement Concerning JP Morgan Complaint Against CAISO*, at 5, Docket No. EL12-70-000 (filed June 19, 2012) (hereinafter referred to as "Enforcement's June 2012 Submission").

[19] *See id.* at 7. Hereinafter, the Office of Enforcement's June 24, 2011 email and its July 28, 2011 email will together be referred to as "the 2011 emails."

[20] *See id.*

[21] *See* JP Morgan Response to Show Cause Order at Att. 23 (letter from CAISO to JP Morgan).

[22] *Id*.

[23] *Id.*

the 2011 emails from the Office of Enforcement.[24] Attached to the email was a letter in which the Office of Enforcement included copies of the 2011 emails to JP Morgan's outside counsel confirming the DMM's authorization to continue to seek information responsive to Request No. 4 and Request No. 5 of the CAISO DMM's May 4 data request.[25]

A. October 18, 2011 Data Response to the CAISO DMM

13. In an October 18, 2011 letter to the DMM, JP Morgan's outside counsel provided additional materials but continued to cite the CAISO Tariff section 11.1 and to characterize its submission of materials as voluntary.[26]

14. In an October 27, 2011 letter, JP Morgan's outside counsel responded to the CAISO's September 27, 2011 notice of penalty for failure to timely submit discovery responses as required under the CAISO Tariff.[27] JP Morgan counsel asserted that "J.P. Morgan had a good faith belief it was responding to the DMM on a voluntary, as opposed to a mandatory, basis" and again cited the CAISO Tariff section 11.1.[28]

15. In a December 5, 2011 letter to JP Morgan, CAISO stated that it had revised its earlier determination to find that JP Morgan's responses to Request No. 4 and Request No. 5 of the DMM's May 4 data request were 162 days late, rather than the 30 days indicated in the September 27, 2011 letter.[29] CAISO determined that information responsive to Request No. 4 and Request No. 5 was due by May 18, 2011 and JP Morgan failed to provide a full response until October 27, 2011. In this revised notice, CAISO stated its position on JP Morgan's repeated assertions of "voluntary" disclosures:

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[24] *See Submission by Office of Enforcement Concerning JP Morgan Motion to Withdraw Complaint Without Prejudice*, at 16-22 (filed July 3, 2012) (hereinafter referred to as "Enforcement's July 2012 Submission").

[25] *Id.*

[26] *See* JP Morgan Response to Show Cause Order at Att. 21 (letter from JP Morgan's outside counsel to the DMM) (October 18, 2011 Data Response to the CAISO DMM).

[27] *See* JP Morgan Response to Show Cause Order at Att. 24 (letter from JP Morgan's outside counsel to CAISO).

[28] *Id.*

[29] *See* JP Morgan Response to Show Cause Order at Att. 25 (letter from CAISO to JP Morgan).

> In providing its response, the ISO reminds [JP Morgan] that, contrary to any suggestions made in the October 27 letter or elsewhere, the ISO has never viewed [JP Morgan]'s compliance with the May 4 data requests as voluntary and communicated that point to [JP Morgan] in advance of the initial May 18, 2011 due date.

16. In a February 13, 2012 letter, CAISO notified JP Morgan that it had decided to impose a financial penalty of $486,000 against JP Morgan for failing to submit all responsive materials to CAISO by the deadline established in the May 4 data request.[30] The letter stated:

> The ISO's determination is based, in part, on its view that the [DMM's] May 4, 2011 Information Request did not violate Appendix P, Section 11.1 of the ISO Tariff and, as such, was validly issued. Compliance with the Information request was thus mandatory, not voluntary, under the ISO Tariff.[31]

B. <u>March 21, 2012 Appeal</u>

17. On March 21, 2012, JP Morgan filed with the Commission a non-public appeal of CAISO's decision to impose the monetary penalty for violation of the CAISO Tariff.[32] Among other things, JP Morgan continued to argue that its responses to the May 4 data request were "completely voluntary" and that, pursuant to sections 11.1 and 11.5 of the Tariff, the DMM was divested of its authority to continue its investigation and impose a monetary penalty.[33] Further, JP Morgan stated that it "reasonably concluded as of March 9, 2011—and continues to conclude—that any responses to the DMM after that date were completely voluntary and that the assessed penalty has no basis under the CAISO Tariff."[34]

18. On April 20, 2012, in a non-public order, the Commission rejected JP Morgan's appeal as procedurally deficient.

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[30] *See* Enforcement's July 2012 Submission, at 27.

[31] *Id*.

[32] JP Morgan, Non-Public Appeal, Docket No. IN11-08-000 (filed Mar. 21, 2012) (March 21, 2012 Appeal).

[33] *Id.* at 8-10.

[34] *Id.* at 10.

C. May 21, 2012 Complaint

19. On May 21, 2012, pursuant to section 206 of the FPA, JP Morgan filed a complaint alleging that the monetary penalty imposed by CAISO for JP Morgan's alleged failure to timely respond to the May 4 data request is unjust, unreasonable and unduly discriminatory.[35] Among other things, JP Morgan argued that CAISO's imposition of the monetary penalty and continued efforts to obtain information in response to the May 4 data request after CAISO had referred the matter to the Office of Enforcement violated sections 11.1 and 11.5 of the Tariff.[36] According to JP Morgan, once CAISO referred the matter to the Office of Enforcement, sections 11.1 and 11.5 of the Tariff prohibited CAISO from taking any further action against JP Morgan in the absence of an "'express direction of FERC or FERC Staff.'"[37] Notably, JP Morgan also stated in the May 21, 2012 Complaint:

> Neither the DMM nor [the Office of Enforcement] informed [JP Morgan] that the DMM had been authorized or instructed to continue to seek responses to the DMM's May 4 Requests—or any other request—either at the direction of [the Office of Enforcement] or the Commission under Section 11.5 or the monitoring clause of Section 11.1.
>
> When [the Office of Enforcement] later requested that [JP Morgan] provide specific documents to the DMM, there was no suggestion that [the Office of Enforcement] was triggering the "express direction" exception in Section 11.5 or that [JP Morgan] had an on-going duty to respond to the May 4 Requests.
>
> Therefore, it was entirely reasonable for [JP Morgan] to believe that the DMM had no legal basis for mandating information from the company relating to the relevant 2010 and 2011 bidding activity.[38]

20. In response to JP Morgan's May 21, 2012 Complaint, the Office of Enforcement submitted a response quoting the 2011 emails to show that the Office of Enforcement had informed JP Morgan and its counsel more than once that it had expressly directed the

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[35] May 21, 2012 Complaint at 2.

[36] *Id.* at 1-5.

[37] *Id.* at 12-13 (quoting section 11.5).

[38] *Id.* at 13 (Spaces have been inserted between sentences for clarity).

DMM to continue to seek data responses from JP Morgan because the DMM was authorized to continue analyzing materials to assist Commission staff.[39]

D. June 22, 2012 Answer

21. Following the Office of Enforcement's June 2012 Submission, JP Morgan filed a motion to withdraw its complaint,[40] and an answer to Enforcement's submission in which JP Morgan acknowledged that the March 21, 2012 Appeal and May 21, 2012 Complaint contained a "factual error."[41]

22. Specifically, in its June 22, 2012 Answer, JP Morgan acknowledged that in filing its March 21, 2012 Appeal and May 21, 2012 Complaint, it "failed to bring to the Commission's attention [the 2011] emails."[42] JP Morgan asserted that at the time it prepared and submitted these filings with the Commission, its outside counsel who had received and viewed the 2011 emails "did not recall" their existence "and did not otherwise connect them with the issues addressed in the Complaint, or in the previously filed Appeal."[43] JP Morgan stated that its omission of relevant communications with the Office of Enforcement in its filings with the Commission was in part due to outside counsel's receipt of these emails nearly a year earlier and the fact that the 2011 emails "did not expressly refer to section 11.5 of Appendix P to the CAISO Tariff."[44]

23. On July 3, 2012, the Office of Enforcement filed a submission to address the statements and assertions JP Morgan made to the Commission in its June 22, 2012 Answer.[45] The Office of Enforcement stated that despite the claim that JP Morgan's outside counsel (at Sutherland, Asbill and Brennan LLP) did not forward the 2011 emails to its co-counsel (at Skadden, Arps, Slate, Meagher & Flom, LLP), their client—JP Morgan—had itself received copies of those communications prior to its filing of the March 21, 2012 Appeal and May 21, 2012 Complaint.[46]

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[39] *See* Enforcement's June 2012 Submission.

[40] *Motion to Withdraw 206 Complaint*, Docket No. EL12-70-000 (filed June 20, 2012).

[41] *Answer to Enforcement Staff's Submission Concerning Complaint*, Docket No. EL12-70-000, at 1 (filed June 22, 2012) (June 22, 2012 Answer).

[42] *Id*.

[43] *Id. at 2.*

[44] *Id.* at 1-2.

[45] Enforcement's July 2012 Submission.

[46] *Id*. The October 15, 2011 email from the Office of Enforcement is discussed *supra* in P 12.

24. In the September 20, 2012 Show Cause Order, the Commission preliminarily found that the: (1) October 18, 2011 Data Response to the CAISO DMM; (2) the March 21, 2012 Appeal of the CAISO Penalty; (3) the May 21, 2012 Complaint; and (4) the June 22, 2012 Answer may constitute violations of section 35.41(b) of the Commission's regulations.[47] Consequently, the Commission directed JP Morgan to show cause why it should not be found to have violated section 35.41(b). In addition, the Commission directed JP Morgan to show cause why its authority to sell electric energy, capacity, and ancillary services at market-based rates should not be suspended.

II. Notice and Responsive Pleadings

25. Notice of this proceeding was published in the *Federal Register*, 77 Fed. Reg. 59,184 (2012), with JP Morgan's answer, as well as interventions, comments and protests due on or before October 17, 2012. JP Morgan filed its show cause response on October 17, 2012. Timely motions to intervene were filed by Invenergy Thermal Development LLC; Duquesne Power, LLC; Trans Bay Cable LLC; Pacific Gas and Electric Company; and Southern California Edison Company. A motion to intervene and comment was filed by CAISO.

III. Discussion

A. Procedural Matters

26. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2012), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

B. Substantive Matters

1. Violation of Section 35.41(b)

a. Show Cause Response

27. JP Morgan argues that the statements identified in the Show Cause Order do not constitute violations of section 35.41(b) for four reasons.[48] First, JP Morgan contends

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[47] Show Cause Order, 140 FERC ¶ 61,227 at P 14. In the Show Cause Order, these statements were referred to as, "the October 18 Statement," "the March 21 Statements," "the May 21, 2012 Statements," and "the June 22, 2012 Statements."

[48] JP Morgan Response to Show Cause Order at 22-31.

that no violation has occurred because it observed adequate due diligence procedures.[49] In support of this assertion, JP Morgan explains that it hired "experienced, well-respected lawyers who specialized in the specific tasks at hand: handling discovery issues involving CAISO and [the Office of Enforcement]."[50] In addition to its in-house counsel, JP Morgan explains that two experienced law firms reviewed the October 18, 2011 Data Response to the CAISO DMM[51] and three law firms reviewed the March 21, 2012 Appeal before it was filed with the Commission.[52]

28. Regarding both the March 21, 2012 Appeal and the May 21, 2012 Complaint, JP Morgan confirms that it "failed to mention or address contextually the June 24 and July 28 Emails, either on a stand-alone basis or as attachments to the October 15 letter."[53] Despite these failures, JP Morgan states that it "took sufficient, if imperfect, due diligence steps to comply with section 35.41(b)."[54] Further, JP Morgan states that it repeatedly expressed its position that its production of information to CAISO was voluntary. JP Morgan suggests that the repeated "ventilating" of its position evidences its good-faith effort to prevent misstatements.[55]

29. Second, JP Morgan contends that no violation has occurred because the "communications and actions—or lack thereof—of the Commission and CAISO help explain how [JP Morgan's] misunderstanding continued unabated for over a year."[56] JP Morgan states that it was never provided with information "in which [the Office of Enforcement] expressly directed CAISO to continue its post-referral investigation."[57] JP Morgan further asserts that CAISO never informed JP Morgan that the Office of Enforcement had expressly directed CAISO to take investigative measures following the

[49] *Id.* at 22-24 JP Morgan also states that section 35.41(b) only prohibits knowing violations. *Id.* (citing *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218, at PP 96, 110 (2003), *reh'g denied*, 107 FERC ¶ 61,175 (2004)).

[50] *Id.* at 23.

[51] *Id*. at 28.

[52] *Id*. at 24.

[53] *Id*. at 29-30.

[54] *Id.* at 30.

[55] *Id.* at 24.

[56] *Id.* at 25.

[57] *Id.*

DMM's referral.[58] Moreover, JP Morgan claims that prior to filing Enforcement's June 2012 Submission in response to the May 21, 2012 Complaint, the Office of Enforcement never informed JP Morgan that CAISO had been expressly directed to continue its investigation pursuant to section 11.5.[59]

30. In addition, JP Morgan describes an email sent on May 17, 2012 from the Office of Enforcement to JP Morgan's outside counsel and asserts that the Office of Enforcement staff "refused to answer" JP Morgan's inquiry as to whether the Office of Enforcement's use of the phrase "expressly directed" was intended to invoke section 11.5.[60] JP Morgan contends that on May 17, 2012, the Office of Enforcement sent JP Morgan's representatives an email that "used similar 'expressly directed' language" as is contained in the 2011 emails.[61] JP Morgan states:

> Having raised in the [March 21, 2012 Appeal], and planning to raise in the [May 21, 2012 Complaint], similar issues, and in order to understand clearly what the May 17, 2012 email meant, [JP Morgan] asked [the Office of Enforcement] directly whether the "expressly directed" language was meant to invoke [s]ection 11.5. [The Office of Enforcement] refused to answer this question, and merely responded that it was important that [JP Morgan] "cooperate." This was consistent with [the Office of Enforcement's] actions from June 2011 to June 2012.[62]

31. Third, JP Morgan argues that the October 18, 2011 Data Response to the CAISO DMM, the March 21, 2012 Appeal, the May 21, 2012 Complaint, and the June 22, 2012 Answer do not contain knowingly false or misleading information.[63] JP Morgan asserts that the October 18, 2011 Data Response to the CAISO DMM accurately reflects its view at the time that the Office of Enforcement's October 15, 2011 letter sought voluntary cooperation, rather than mandatory compliance.[64] JP Morgan further contends that the March 21, 2012 Appeal and the May 21, 2012 Complaint were the product of an

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[58] *Id.*

[59] *Id.* at 26.

[60] *Id.* at 27, n.83.

[61] *Id.* Hereinafter, this email will be referred to as "the May 17, 2012 email."

[62] *Id.*

[63] *Id.* at 27-31.

[64] *Id.* 27-28.

inadvertent oversight during a period in which the "frequency and intensity of communications and discovery in this investigation reached very high levels. . . ."[65]

32. JP Morgan rejects the Commission's preliminary finding that the June 22, 2012 Answer may be false or misleading or contain material omissions.[66] According to JP Morgan, its filing "simply expresses [JP Morgan's] regret for the errors that occurred and provides information explaining the reasons for that mistake."[67] JP Morgan further asserts that statements in its June 22, 2012 Answer "confirmed that [JP Morgan] acted with good faith and with no intent to mislead anyone."[68]

33. In support of its contention that the statements identified in the Show Cause Order did not knowingly contain false or misleading information, JP Morgan provides several affidavits by individuals closely involved in the preparation of the statements identified in the Show Cause Order. The affidavits generally state that each individual either did not recall the existence of the 2011 emails or believed that the 2011 emails set forth a request by the Office of Enforcement that JP Morgan voluntarily provide additional information to the CAISO DMM.[69]

34. Fourth, JP Morgan suggests that it could not have misled the Commission or CAISO by filing the March 21, 2012 Appeal and the May 21, 2012 Complaint , which "both omitted citation to the FERC Communications" because the information contained in the 2011 emails "was already in [the Commission's] possession."[70] JP Morgan

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[65] *Id.* at 29.

[66] *Id*. at 30.

[67] *Id*.

[68] *Id*.

[69] *See e.g.*, Krupka Aff. ¶ 3 ("I read the June 24 Email as a request from the Federal Energy Regulatory Commission's Office of Enforcement Staff asking, rather than compelling, JPMVEC to provide information to the DMM."); Phillips Aff. ¶ 2 ("I did receive the October 15, 2011 sent by email from Enforcement staff to Diane Genova . . . . However, I do not recall reviewing the attachments to that email at that time."); Raisler Aff. ¶ 4 ("Although I appear to have seen in July 2011 one or both of the June 24, 2011 and July 28, 2011 emails from OE staff to Catherine Krupka . . . at the time of the filing of the [October 18, 2011 2011 Data Response to the CAISO DMM, the March 21, 2012 Appeal of the CAISO Penalty, the May 21, 2012 Complaint, and the June 22, 2012 Answer] I did not remember, or recall the existence of, the June 24 Email and the July 28 Email. . . ."); *see generally,* Genova Declaration ¶¶ 3-5; Konieczny Aff. ¶¶ 6-8; and Nakkab Aff. ¶¶ 3-4.

[70] JP Morgan Response to Show Cause Order at 31.

contends that had it "recalled the FERC Communications and realized their import, it would have referenced them."[71]

b. <u>Commission Determination</u>

35. We find that the statements identified in the Show Cause Order each constitute individual violations of section 35.41(b). Section 35.41(b) of the Commission's regulations requires sellers to provide accurate and factual information and prohibits sellers from submitting false or misleading information or omitting material information in any communication with the Commission, market monitors, independent system operators, regional transmission organizations, and jurisdictional transmission providers, unless the seller can demonstrate that it has exercised due diligence to prevent such occurrences.[72]

36. The record demonstrates that the Office of Enforcement informed JP Morgan and its outside counsel on at least three separate occasions through the 2011 emails and a letter that it had expressly directed the DMM to continue its investigation of JP Morgan's bidding activities and to seek responses to CAISO's May 4 data request.[73] JP Morgan both failed to disclose its receipt of these communications and submitted statements in filings with the Commission that falsely stated that it had no knowledge that the Office of Enforcement had expressly directed the DMM to continue seeking information from JP Morgan.[74]

37. The Commission has explained that section 35.41(b) only applies if a seller submits: (i) "false or misleading information"; or (ii) if the seller "omits material information" in "any communication" to the Commission or one of the entities specified in section 35.41(b). The statements contained in each of the communications identified in the Show Cause Order failed to satisfy the standard established in the Commission's regulations. With respect to the October 18, 2011 Data Response to the CAISO DMM and the March 21, 2012 Appeal, JP Morgan falsely asserted to the DMM and the

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[71] *Id*.

[72] 18 C.F.R. § 35.41(b); *see also Cobb Customer Requesters v. Cobb Elec. Membership Corp.*, 136 FERC ¶ 61,084, at P 42 (2011). For the purpose of section 35.41(b), the Commission's regulations define the term "seller" to mean "any person that has authorization to or seeks authorization to engage in sales for resale of electric energy, capacity or ancillary services at market-based rates under section 205 of the [FPA]." 18 C.F.R. § 35.36 (2012).

[73] *See* JP Morgan Response to Show Cause Order at Att. 9; Enforcement's June 2012 Submission at 7; Enforcement's July 2012 Submission at 16-22.

[74] *See* Enforcement's July 2012 Submission at 9, 13, App. A.

Commission respectively, that JP Morgan's responses to the DMM were voluntary pursuant to section 11.1 of the Tariff. Regarding the May 21, 2012 Complaint, JP Morgan falsely stated that the Office of Enforcement had not informed JP Morgan that the DMM had been authorized to continue to seek responses to the May 4 data request. As the record illustrates, JP Morgan's statements in its communications with the CAISO DMM and filings with the Commission were not only inaccurate, but omitted material information.

38. In its June 22, 2012 Answer, JP Morgan acknowledges it "failed to bring to the Commission's attention [the 2011] emails," in its submission of the March 21, 2012 Appeal and May 21, 2012 Complaint. However, despite this admission, the June 22, 2012 Answer also fails to comport with the requirements of section 35.41(b). While the June 22, 2012 Answer attempts to draw support from several affidavits of individuals at JP Morgan and JP Morgan's counsel,[75] it is not credible that JP Morgan's representatives failed to recall or appreciate the significance of the 2011 emails and the Office of Enforcement's October 15, 2011 letter, especially in its preparation of the October 18 Data Response to the CAISO DMM.

39. JP Morgan's position also lacks credibility because of the May 17, 2012 email exchange with the Office of Enforcement.[76] In the May 17, 2012 email addressed to JP Morgan with the Subject line: "Confirming [the Office of Enforcement's] express directive to CAISO Market Monitor, and request to JP Morgan to cooperate with the MMU," the Office of Enforcement wrote, in part:

> This is to advise you that the Office of Enforcement has expressly authorized and directed the CAISO Market Monitor to continue to seek from JP Morgan answers . . . to any other questions (or provision of any other relevant data) that the Market Monitor believes may be helpful in understanding the bidding behaviors mentioned. . . .
>
> We have also advised the CAISO Market Monitor that, if they believe live interviews of the responsible traders would be more informative than getting written answers to written questions, they should seek to conduct the interviews. We hereby request that, if asked, JP Morgan promptly

[75] *See* Krupka Aff. ¶¶ 3-9; Konieczny Aff. ¶¶ 6-8; Phillips Aff. ¶¶ 3-5; Raisler Aff. ¶¶ 4, 7; Genova Declaration at ¶ 4; Nakkab Aff. ¶ 3.

[76] *See supra* P 30.

> (within three business days) make the traders available for any interviews requested by the Market Monitor relating to these topics.[77]

On May 18, 2012—only three days before filing the May 21, 2012 Complaint—JP Morgan's outside counsel replied:

> Thank you for your message. We assume you sent this pursuant to Section 11.5 of Appendix P of the CAISO tariff. However, we have not seen a notice of referral from the CAISO, as has been customary in the past (see attached example) and consistent with Article 37.8 and Appendix P Article 11 of the CAISO tariff. Can you let us know where things stand?[78]

On May 18, 2012, Office of Enforcement staff replied:

> I understand that the MMU is getting in touch with you about this. Meanwhile, I want to reiterate how important it is for JP Morgan to provide full and timely cooperation to the MMU's office, including making the responsible traders available for prompt interviews.[79]

Thus, only three days before filing the May 21, 2012 Complaint, JP Morgan and its outside counsel demonstrated that they understood that the Office of Enforcement's use of phrases virtually identical to the language of section 11.5 of the CAISO Tariff confirmed that Commission staff had authorized the CAISO DMM to continue its investigation of JP Morgan's bidding activities pursuant to that provision.[80] JP Morgan's contention that the Office of Enforcement staff "refused" to clarify whether the "expressly directed" language was intended to invoke section 11.5 is meritless. JP Morgan's response to the May 17, 2012 email confirms that in the days immediately

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[77] *Id*. May 17, 2012, 7:34pm email from Office of Enforcement Staff to JP Morgan and JP Morgan's outside counsel.

[78] *Id.* May 18, 2012, 3:37pm email from JP Morgan's outside counsel to Office of Enforcement staff.

[79] *Id*. May 18, 2012, 5:40pm email from Office of Enforcement Staff to JP Morgan and JP Morgan's outside counsel.

[80] Section 11. *Protocol on Referrals of Investigations to the Office of Enforcement* provides in section 11.5 that the DMM may continue to "undertake any investigative steps regarding the referral" if expressly directed by Commission staff. Notably, section 11.1 provides that even after a referral has been made to the Commission, the "DMM may, however, continue to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. DMM shall respond to requests from FERC for any additional information in connection with the alleged Market Violation it has referred."

preceding JP Morgan's submission of the May 21, 2012 Complaint, JP Morgan's representatives in fact fully understood and appreciated the significance of the "expressly directed" language included in the 2011 emails, even in the absence of a specific reference to section 11.5 or 11.1 of the CAISO Tariff. And yet, JP Morgan filed the May 21, 2012 Complaint without mentioning the existence or knowledge of these 2011 emails from the Office of Enforcement. Therefore JP Morgan lacks any good faith basis for interpreting its cooperation as voluntary.

40. We find that the various communications provided to JP Morgan by the Office of Enforcement staff, which contained the precise tariff language at issue, informed JP Morgan that the post-referral bar provided in section 11.1 of the Tariff was no longer in effect and adequately apprised JP Morgan of CAISO's authority to continue its investigation pursuant to section 11.5 of the CAISO Tariff. As discussed above, the Office of Enforcement repeatedly confirmed for JP Morgan that the Office of Enforcement had expressly directed the CAISO DMM to continue to seek responses to the May 4 data request. The fact that the 2011 emails did not specifically cite section 11.5 or 11.1 is inconsequential.[81]

41. JP Morgan's response to the Show Cause Order that it always believed that its production of information to the DMM was voluntary lacks credibility and cannot be reconciled with a rational reading of the emails from the Office of Enforcement. The 2011 (and 2012) email communications with the Office of Enforcement *directly* relate to the argument JP Morgan puts forth in its March 21, 2012 Appeal and May 21, 2012 Complaint. In sum, viewed in light of the entire record, the explanation provided in the June 22, 2012 Answer that JP Morgan "did not recall that the 2011 [e]mails existed and did not otherwise connect them with the issues addressed in the Complaint"[82] lacks credibility. Furthermore, section 35.41(b) requires the exercise of due diligence, which may extend beyond reliance on memory.

42. Contrary to JP Morgan's assertions, its retainer of qualified attorneys does not constitute sufficient due diligence to exonerate JP Morgan's violations. At the time the Commission implemented Market Behavior Rule 3, the predecessor of section 35.41(b), the Commission was well aware of the fact that the vast majority of entities that interact with the Commission do so through or with the assistance of competent counsel. Had the Commission intended the assistance of counsel to satisfy the due diligence exception, it need not have established the exception at all because sellers would be excused from virtually all misrepresentations or material omissions.

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[81] We note, moreover, that section 11.5 contemplates communication between the Commission and the DMM but does not require the Commission to give notice to the subject.

[82] June 22, 2012 Answer at 1.

43. Further, we fail to see how JP Morgan's representatives exercised the "best-practice due diligence . . . that companies should take to address government investigations."[83] Absent in JP Morgan's response to the Show Cause Order is any explanation or description of how its counsel performed due diligence to ensure that all statements it made to the Commission in those filings were accurate. Instead, JP Morgan's response suggests that reliance on counsels' memories was "sufficient, if imperfect, due diligence."[84] We disagree with this suggestion, particularly in light of the fact that one of the misrepresentations occurred a mere three days after JP Morgan received notice from the Office of Enforcement staff of its express direction to CAISO to continue to seek data, and demonstrated in a reply to Office of Enforcement staff that it understood the import of that notice. Moreover, as we explain elsewhere in this order, JP Morgan's suggestion that it failed to recall its correspondence with the Office of Enforcement staff on this matter is not credible.

44. Further, JP Morgan's repeated "ventilating" of its position that its production of information to CAISO was voluntary does not demonstrate the exercise of due diligence because it in no way suggests that JP Morgan took steps to avoid the misrepresentations at issue. Rather, such reiteration better demonstrates JP Morgan's failure to exercise due diligence despite the various communications it received from the Office of Enforcement staff stating that staff had expressly directed CAISO to continue to seek responses to all data requests issued before June 20, 2011. Moreover, JP Morgan's characterization of its discovery responses to the DMM does not change the obligation under the Tariff for it to timely and comprehensively respond to the DMM.

45. JP Morgan's contention that none of the statements at issue contain knowingly false or misleading information, as explained by the various affidavits filed by JP Morgan in support of its position, offers no defense in this case. As discussed above, it is a violation of section 35.41(b) when a seller submits false or misleading information or omits material information in an applicable communication unless the seller demonstrates it has exercised due diligence to prevent such an occurrence. No showing of the respondent's intent or mindset is necessary in order to demonstrate that a violation of section 35.41(b) has occurred.[85] The Commission has explained that the due diligence exception was added to the Commission's rules for the purpose of ensuring that

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[83] *See* JP Morgan Response to Show Cause Order at 23-24.

[84] *See id*. at 30.

[85] *See Moussa I. Kourouma*, 135 FERC ¶ 61,245, at PP 20-22 (2011) (*Kourouma*).

inadvertent submissions are not sanctioned.[86] Thus, the Commission's task is first, to determine whether a qualifying misrepresentation or material omission has been made, and second, to the extent necessary, to evaluate whether the seller has exercised due diligence. JP Morgan's intent or state of mind is irrelevant to this inquiry because neither demonstrates the veracity or accuracy of JP Morgan's assertions or that JP Morgan exercised due diligence to ensure the accuracy of its communications with the CAISO and the Commission in this case.

46. Similarly, JP Morgan's suggestion that it could not mislead the Commission or CAISO about information that was already in the Commission's possession in no way demonstrates that the statements identified in the Show Cause Order do not violate section 35.41(b). The objective accuracy of a seller's statements is the regulation's central requirement. JP Morgan's purported inability to mislead CAISO, the DMM, or the Commission neither shows that the statements at issue were accurate nor that JP Morgan exercised due diligence. Further, a straightforward reading of the text of that provision dispels JP Morgan's interpretation that the Commission's rules would allow an entity to submit inaccurate information or omit material information, either intentionally or through its failure to exercise due diligence, so long as the entity ultimately failed to mislead the recipient. The regulation does not require that the recipient actually be misled or even be capable of being misled in order for communications containing misleading statements or material omissions to be deemed violations of section 35.41(b).

47. The failure of JP Morgan and its attorneys to acknowledge the existence of the 2011 emails from the Office of Enforcement staff in its March 21, 2012 Appeal and May 21, 2012 Complaint, together with the existence of the May 17-18, 2012 email exchange demonstrating counsel's awareness that Commission staff had authorized the ongoing DMM investigation, raises particular concerns under the circumstances. We remind counsel that as representatives of those sellers that have authorization to or seek authorization to engage in sales for resale of electric energy, capacity or ancillary services at market-based rates under section 205 of the FPA, they are required under Commission regulations to ensure the veracity and accuracy of the pleadings they file with the Commission, and that Commission regulations provide various ways of addressing circumstances in which those requirements have not been met.[87]

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[86] *Kourouma*, 135 FERC ¶ 61,245 at P 21 (discussing *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 110); *see also Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 110 (revising the initially proposed rule to include the due diligence exception to "assure that inadvertent submission of inaccurate or incomplete information will not be sanctioned.").

[87] *See, e.g.*, 18 C.F.R. § 385.2102(a) (2012).

2. Suspension of Market-Based Rate Authority

a. Show Cause Response

48. Assuming for the sake of argument that any of the statements identified in the Show Cause Order constitute a violation of section 35.41(b), JP Morgan argues that such a violation does not warrant suspension of its market-based rate authority.[88] JP Morgan states that suspension of a seller's market-based rate authority is a severe penalty.[89] Further, JP Morgan explains that the Commission has committed to consider the circumstances surrounding a given violation in assessing non-monetary penalties to ensure that such penalties are appropriate and in proportion to the severity of the applicable violation.[90] Additionally, JP Morgan argues that the statements at issue caused no economic harm and were not made knowingly or with the intent to deceive the DMM or the Commission.

49. JP Morgan also argues that the Commission may only punish a seller's OATT violation where the Commission identifies a nexus between the violation and the entity's market-based rate authority.[91] In this case, JP Morgan contends that no such nexus exists. Specifically, JP Morgan states that the statements identified in the Show Cause Order pertain to a discovery-related directive, rather than JP Morgan's market-based rate authority or its selling or trading activities.[92] Moreover, JP Morgan argues that the

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[88] JP Morgan Response to Show Cause Order at 31 (citing *Investigations of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 110).

[89] *Id.* at 32.

[90] *Id.* at 32 (citing *Enforcement of Statutes, Orders, Rules, and Regulations,* 113 FERC ¶ 61,068, at P 1 (2005)).

[91] *Id.* (citing *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 417, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g,* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g,* Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC,* 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC,* 21012 U.S. LEXIS 4820 (U.S. June 25, 2012)).

[92] *Id.* at 33.

statements were not made in the course of a Commission proceeding addressing market-based rates.[93]

50. Finally, JP Morgan contends that its representatives argued based on a good-faith belief that section 11.1 applied because the exception provided in section 11.5 had not been triggered. According to JP Morgan, the Commission has previously "explained that 'a subject's good faith exercise of its rights under the relevant statutes and our regulations, including but not limited to good faith disputes regarding discovery or settlement issues, will not be considered in determining whether the subject of an investigation has cooperated with staff and will not cause the subject of an investigation to forego possible credit for exemplary cooperation.'"[94]

b. Comment

51. CAISO states that serious sanctions are appropriate if a seller submits material misrepresentations.[95] CAISO explains that it is essential that market participants act with candor and honesty in responding to requests for information in the course of an investigation. CAISO notes that such candor is especially significant in the course of a market monitor's investigation of potential market misconduct. As a result, CAISO supports "decisive action" where a market participant has failed to comport to the Market Behavior Rules, and believes that suspension of market-based rate authority or some similar sanction could be appropriate for such a violation.[96]

52. CAISO also urges the Commission to consider operational factors that may affect the markets administered by CAISO in determining whether to suspend JP Morgan's market-based rate authority.[97] CAISO explains that the generating units controlled by JP Morgan and its subsidiaries play a significant role in enabling CAISO to reliably meet demand. CAISO asserts that any remedy imposed should not result in CAISO losing access to the energy and capacity provided by those facilities. However, CAISO observes that the significance of those units offers no basis for reducing the severity of any sanction imposed by the Commission and that, in fact, the opposite may be true.

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[93] *Id.* JP Morgan encourages the Commission to refrain from "blurring the boundary between its ratemaking and enforcement authority." *Id.* at 34.

[94] *Id.* at 31, n.95 (citing *Enforcement of Statutes, Regulations and Orders*, 123 FERC ¶ 61,156, at P 22 (2008)).

[95] CAISO Comment at 4.

[96] *Id.* at 5.

[97] *Id.* at 7-8.

c. Commission Determination

53. As discussed above, we find that the statements identified in the Show Cause Order each represent violations of section 35.41(b). On numerous occasions, the Commission has explained that companies failing to adhere to the proper standards are subject to immediate revocation of their market-based rate authority.[98] Accordingly, we will suspend JP Morgan's authority to sell energy, capacity, and ancillary services at market-based rates for a period of six months, to become effective on April 1, 2013. JP Morgan will only be allowed to participate in wholesale electricity markets by either scheduling quantities of energy products without an associated price or by specifying a zero-price in their offer, as the relevant tariffs require. Furthermore, the rate received by JP Morgan will be capped at the higher of the applicable locational marginal price or its default energy bid. The Commission has previously accepted the default energy bid as a reasonable opportunity to recover costs.[99] Such a cap will also ensure that load-serving entities have access to adequate generating capacity to serve demand. However, given CAISO's stated concern that the generating units controlled by JP Morgan and its subsidiaries play a significant role in enabling CAISO to reliably meet system needs, we will delay the suspension until April 1, 2013. Such a delay will allow CAISO sufficient time to take steps necessary to maintain system reliability during the suspension period. Such a delay will also afford JP Morgan time to make alternative arrangements to fulfill any existing contractual obligations that may be affected. For instance, JP Morgan would have the option to file for cost-based rates pursuant to which it could be authorized to sell energy, capacity, and ancillary services during the suspension period.

54. JP Morgan's misrepresentations and the resulting penalty are most appropriately addressed at this time because the facts underlying the Office of Enforcement's ongoing investigation and the aforementioned violations are distinct. Consequently, we will not exercise the Commission's right to defer consideration of the matter until the Office of Enforcement has concluded its investigation.[100] The principal issue in the Office of

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[98] *See, e.g.*, *Enforcement of Statutes and Regulations and Orders*, 123 FERC ¶ 61,156 at P 49; *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 114 FERC ¶ 61,165, at P 32 (2006); *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218, at P 6, 146, 151; *Enron Power Mktg., Inc.*, 102 FERC ¶ 61,316, at P 8 (2003) (citing *Fact Finding Investigation of Potential Manipulation of Elec. and Natural Gas Prices*, 99 FERC ¶ 61,272, at 62,153-54 (2002); *accord Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 97 FERC ¶ 61,220, at 61,975-77 (2001); *GWF Energy, LLC*, 98 FERC ¶ 61,330, at 62,390 (2002)).

[99] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1033-1057 (2006).

[100] *See* Show Cause Order, 140 FERC ¶ 61,227 at P 15.

Enforcement's investigation is whether JP Morgan's trading behavior constitutes market manipulation in violation of section 222 of the FPA[101] and Part 1c of the Commission's regulations.[102] The communications containing misrepresentations and material omissions that are at issue in this case, however, occurred several months after the trading behavior referred by the DMM took place. Additionally, while the October 18, 2011 Data Response to the CAISO DMM and the March 21, 2012 Appeal were made in the course of the Office of Enforcement's investigation, the May 21, 2012 Complaint and the June 22, 2012 Answer were made in a separate proceeding pursuant to section 206 of the FPA.

55. Separate consideration of JP Morgan's false statements is also appropriate because the principal causes of action in the respective proceedings are distinct. The Commission has previously explained that a violation of section 222 has occurred where an entity:

> (1) uses a fraudulent device, scheme or artifice, or makes a material representation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engages in any act, practice, or course of business that operates or would operate as a fraud or deceit on any entity; (2) with the requisite scienter; (3) in connection with the purchase or sale of natural gas or electric energy or transportation of natural gas or transmission of electric energy subject to the jurisdiction of the Commission.[103]

In comparison, a violation of section 35.41(b) requires neither a showing of a seller's intent nor a showing that the statements were made in connection with a jurisdictional transaction.[104] In addition, no party has alleged that the statements identified in the Show Cause Order constitute violations of Part 1c of the Commission's regulations.

56. Contrary to JP Morgan's assertion, our decision to address the communications at issue in the current proceeding would not "blur the boundary between [the Commission's] ratemaking and enforcement authority."[105] JP Morgan's argument in favor of deferring our determination until after the Office of Enforcement has concluded its investigation is based on the faulty premise that "[t]he dispute here relates to discovery

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[101] 16 U.S.C. § 824w (2006).

[102] 18 C.F.R. Part 1c (2012) (Part 1c).

[103] *Prohibition of Market Manipulation*, Order No. 670, FERC Stats. & Regs. ¶ 31,202 (2006).

[104] *Compare* 18 C.F.R. § 35.41(b), *with* 18 C.F.R. § 1c.2 (2012), *and* Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 49.

[105] JP Morgan Response to Show Cause Order at 34.

in an ongoing non-public investigation by [the Office of Enforcement]."[106] This premise ignores the legal authority pursuant to which JP Morgan filed communications with the Commission that contained significant misrepresentations and material omissions. The May 21, 2012 Complaint and the June 22, 2012 Answer were filed pursuant to section 206 of the FPA and relate to its allegation that the monetary penalty imposed by CAISO violated the Tariff and was unjust and unreasonable as a result.[107] Moreover, JP Morgan's premise ignores the fundamental role of honesty and candor in the Commission's market-based rate regime, as discussed further below. Thus, our suspension of JP Morgan's market-based rate authority in the current proceeding, separate from the Office of Enforcement's ongoing investigation, would adhere to the boundaries between the Commission's ratemaking and enforcement authorities, rather than blur them.

57. The nature of JP Morgan's violations is of critical importance in this case. The ability to charge market-based rates is a privilege, not a right, and in granting that privilege the Commission relies on the truth and veracity of the demonstrations made by companies when they apply for market-based rate authority. Furthermore, the Commission's grant of market-based rate authority is founded upon the presumption that a company's behavior will not involve fraud, deception or misrepresentation.[108] Consequently, the Commission relies on the submission of complete and accurate information from those that seek authorization to charge market-based rates. Indeed, the provision of false, misleading or inaccurate information undermines the very integrity of the Commission's decision-making process, the Commission's market-based rate regime, as well as the Commission's ability to carry out its statutory obligation to ensure just and reasonable rates. For these reasons, the Commission has continuously warned market participants of the consequences associated with failing to abide by the Commission's rules and regulations.[109]

58. In this light, the egregious nature of JP Morgan's repeated submission of false and misleading statements to CAISO, the DMM, and the Commission requires the severe penalty of suspending JP Morgan's market-based rate authority. Over a period of several months, JP Morgan continuously reasserted its fallacious position that section 11.1 barred the DMM's investigative efforts because the DMM had not been expressly directed to continue its investigation pursuant to section 11.5. The record in this case demonstrates that JP Morgan and its representatives were notified and reminded time and again that this assertion was in fact incorrect. However, JP Morgan and its representatives either

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[106] *Id.*

[107] *See* May 21, 2012 Complaint at 10.

[108] *Enron Power Mktg., Inc.*, 102 FERC ¶ 61,316 at P 8.

[109] *Cf. supra* note 98.

intentionally, recklessly, or negligently ignored the Office of Enforcement's communications and continued to mislead those tasked with ensuring that the CAISO markets functioned properly and resulted in just and reasonable rates.

59. Again, we find JP Morgan's conduct before this Commission particularly troublesome under the circumstances. In the past several months, JP Morgan has submitted three separate filings containing statements that were premised on what are undeniably falsehoods. In the March 21, 2012 Appeal and the May 21, 2012 Complaint, JP Morgan implored the Commission to overturn CAISO's monetary penalty on the basis that the Office of Enforcement had never expressly directed the CAISO DMM to continue its investigation of JP Morgan's bidding activities. These misrepresentations served as the central argument advanced by JP Morgan as it persisted in referring to the post-referral bar of section 11.1. Notably, it was not until the Office of Enforcement called the Commission's attention to the inaccuracy of JP Morgan's assertions that JP Morgan acknowledged "mistakes in the Submissions."[110]

60. JP Morgan's argument that suspension of its market-based rate authority is unwarranted because its various misrepresentations caused no economic harm fails to fully take into account the seriousness of its violations. "The decision of whether to impose [non-monetary sanctions, such as suspending market-based rate authority] is based on an evaluation of the particular circumstances of the individual case, including the scope and seriousness of the violations."[111] The harm caused by a violation, whether it is economic or physical, is merely one factor in determining the appropriate penalty to be imposed. Moreover, as we note above, the Commission's market-based rate program relies on a presumption that those authorized to charge market-based rates will not engage in fraud, deception, or misrepresentation. Thus, misrepresentations by market-based rate sellers are serious violations causing harm to the integrity of the Commission's market-based rate authorizations.

61. Other factors similarly require a severe penalty in this case. For instance, JP Morgan's withdrawal of its complaint cannot be characterized as JP Morgan's having reported its own violation because the Office of Enforcement brought JP Morgan's misrepresentations to light. Only afterward did JP Morgan withdraw its complaint,

[110] *See* JP Morgan Response to Show Cause Order at 25.

[111] *Enforcement of Statutes, Regulations and Orders*, 123 FERC ¶ 61,156, at P 49 (2008); *see also Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216, at P 97 (2010) ("We clarify that the Penalty Guidelines do allow for non-monetary sanctions. The Commission has always had the discretion to assess non-monetary sanctions, instead of or in addition to monetary penalties . . . . The Penalty Guidelines do not change this practice.").

while simultaneously filing the June 22, 2012 Answer, which contained more misrepresentations in violation of section 35.41(b).[112]

62. Similarly, JP Morgan offered no form of cooperation until after its misrepresentations had been exposed. Rather, JP Morgan repeatedly made deceptive and misleading statements to CAISO, the DMM, and the Commission over a period of several months.[113] Although a subject's good faith exercise of its rights is not to be considered as a failure to cooperate with the Commission, JP Morgan failed to act in good faith in this case.[114] At least as early as its receipt of the 2011 emails, JP Morgan could no longer in good faith argue that the DMM had not been expressly authorized by the Office of Enforcement to continue its investigation. Nevertheless, after being informed of the DMM's authority on three separate occasions, JP Morgan continually and disingenuously impeded the DMM's efforts.[115]

63. JP Morgan inappropriately relies on Order No. 697 in arguing that the Commission must establish a nexus between JP Morgan's inaccurate and incomplete statements and its market-based rate authority. In Order No. 697, the Commission stated:

> We will adopt the NOPR proposal to revoke an entity's market-based rate authority *in response to an OATT violation* only upon a finding of a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority, and reiterate our statement in the NOPR that an OATT violation may subject the seller to other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties. As stated in the NOPR, the finding that an OATT adequately mitigates transmission market power rests on the assumption that individual

[112] *See supra* P 21-23, 38.

[113] As discussed above, JP Morgan's assertion that it and its representatives failed to recall the 2011 emails in preparation of the statements identified in Show Cause Order lacks credibility.

[114] *Enforcement of Statutes, Regulations and Orders*, 123 FERC ¶ 61,156 at P 22.

[115] JP Morgan cites a September 30, 2012 article from the *L.A. Times* in support of its statement that the Commission must not act on its violations of 35.41(b) until an enforcement decision in the ongoing investigation is made to "avoid[] the possibility of prejudgment." *See* JP Morgan Response to Show Cause Order at 34, n.101. However, we note that the suggestion in the article that corporate law firms are there to represent their clients' interests by obfuscation, obstruction, delay or misdirecting the Commission from the truth in violation of Commission regulations renders our decision in this matter all the more relevant and important.

> entities comply with the OATT and there may be OATT violations in circumstances that, after applying the factors in the Enforcement Policy Statement, merit revocation or limitation of market-based rate authority. We find, however, that it is inappropriate to revoke a seller's market-based rate authority *for an OATT violation* unless there is a nexus between the specific facts relating to the OATT violation and the seller's market-based rate authority.[116]

A straightforward reading of Order No. 697 makes clear that the nexus requirement set forth in that order for revocation of market-based rate authority is limited to cases involving OATT violations. In this case, JP Morgan has been found to have violated section 35.41(b) of the Commission's regulations—not any provision of the OATT. Thus, the passage of Order No. 697 cited by JP Morgan is inapplicable under the circumstances. Nevertheless, there is a nexus between JP Morgan's misleading statements and its market-based rate authority in that, as noted above, the Commission relies on accurate and complete information from those that it authorizes to charge market-based rates.

3. JP Morgan Subsidiaries

a. Comment

64. CAISO suggests that the Commission consider expanding the scope of this proceeding to include JP Morgan's subsidiary BE CA LLC (BE CA), which CAISO states may have been involved in the conduct at issue in the Show Cause Order.[117] According to CAISO, in a separate proceeding, JP Morgan has explained that it operates in the CAISO markets through tolling agreements held by JP Morgan and BE CA.[118] Further, CAISO states that BE CA has the right to dispatch the output of certain generating facilities in the CAISO region through tolling agreements. Thus, CAISO suggests that the Commission add BE CA as a respondent to the current proceeding, "if for no other reason than to avoid the risk of having an affiliate of [JP Morgan] circumvent and frustrate any remedy the Commission may determine is appropriate."[119]

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[116] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 417 (footnotes omitted) (emphasis added).

[117] CAISO Comment at 5.

[118] *Id.* at 6 (citing J.P. Morgan Ventures Energy Corporation, Complaint, Docket No. EL12-105-000, at 1 (filed Sept. 14, 2012)).

[119] *Id.*

b. <u>Commission Determination</u>

65. In the Show Cause Order, the Commission directed JP Morgan to demonstrate why it should not be found to have violated section 35.41(b) of the Commission's regulations. The Show Cause Order addresses evidence suggesting that specific statements by JP Morgan may have been inaccurate. Consequently, CAISO's recommendation that the Commission add BE CA as a respondent to the Show Cause Order is beyond the scope of the current proceeding, which is confined to the October 18, 2011 Data Response to the CAISO DMM, the March 21, 2012 Appeal, the May 21, 2012 Complaint, and the June 22, 2012 Answer. Further, there is no evidence in the current record that BE CA has submitted misrepresentations that would violate section 35.41(b). Should evidence of a violation eventually come to light, the Commission will address the matter in a future proceeding.

<u>The Commission orders</u>:

JP Morgan's market-based rate authority is hereby suspended for a period of six months, effective as of April 1, 2013, as discussed in the body of this order.

By the Commission. Commissioner LaFleur is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

J.P. Morgan Ventures Energy Cooperation — Docket No. EL12-103-000

(Issued November 14, 2012)

LaFLEUR, Commissioner, *dissenting*:

The record in this proceeding demonstrates that JP Morgan's alleged misrepresentations do not relate to its conduct in the market, but are instead litigation positions that pertain to whether it had the obligation to provide documents to CAISO after CAISO referred JP Morgan's bidding activities to the Commission.[1] Therefore, I believe the statements should be addressed as part of the ongoing investigation into JP Morgan's bidding activities, either as separate counts of obstruction, or as aggravating circumstances that factor into the determination of any civil penalty.[2]

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[1] Specifically, JP Morgan asserted that the Commission's Office of Enforcement did not expressly direct the Market Monitor to continue its investigation into JP Morgan's market activities, as required by the tariff, and that its production of documents to the Market Monitor was voluntary. *See* Order at PP 3-24.

[2] The Commission has available multiple alternatives for addressing JP Morgan's statements in the context of the ongoing investigation. For example, the Penalty Guidelines provide for adding points to JP Morgan's culpability score, and thus increasing its civil penalty, for obstruction of justice. *Penalty Guidelines §* 1C2.3(e) ("If the organization willfully obstructed or impeded . . . or encouraged obstruction of justice during the investigation or resolution of the instant violation, or, with knowledge thereof, failed to take reasonable steps to prevent such obstruction or impedance . . . add **3** points."). The Commission can also refuse to give JP Morgan any credit for cooperation, which would also result in a larger civil penalty. *Id*. *§* 1C2.3(g). If the Commission still feels that these adjustments do not fully address JP Morgan's statements, it may depart from the Penalty Guidelines and impose a higher penalty. *Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216, at P 32 (2010). Finally, the Commission may bring a separate charge against JP Morgan for making intentional or reckless misrepresentations that result in "substantial interference with the administration of justice." *Penalty Guidelines §* 2C1.1 (defining "substantial interference" in part as causing "the unnecessary expenditure of substantial governmental or Commission resources.").

The Commission's decision to proceed with the suspension represents a novel use of its authority over market-based rates, and is unsupported by its own regulations.[3] In Order No. 697, the Commission recognized that it would be "inappropriate" to revoke an entity's market-based rate authority for a tariff violation unless there is a nexus between the specific facts of the violation and the entity's market-based rate authority.[4] By proceeding with today's order, the Commission departs from this sensible principle and establishes a new and potentially dangerous precedent: an entity can lose its market-based rate authority for litigation positions it takes before the Commission or Commission Staff, even if those positions do not relate to its activity or honesty in the market.

That this new precedent can yield arbitrary results is already clear from today's order. After today, the Commission's policy appears to be that there is a nexus requirement for revoking market-based rates in response to tariff violations, but not for misrepresentations or omissions.[5] The lack of such a requirement only underscores the absence of a clear and

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[3] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 417, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, at P 204, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc.* v. FERC, 21012 U.S. LEXIS 4820 (U.S. June 25, 2012).

[4] Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 417.

[5] Order at P 63 ("A straightforward reading of Order No. 697 makes clear that the nexus requirement set forth in that order for revocation of market-based rate authority is limited to cases involving OATT violations.") In any event, the Commission goes on to claim that there is a nexus between JP Morgan's alleged misrepresentations and its market-based rate authority. Citing *Enron Power Mktg., Inc.*, 102 FERC ¶ 61,316, at P 8 (2003) (*Enron*), the Commission explains that its "grant of market-based rate authority is founded upon the presumption that a company's behavior will not involve fraud, deception or misrepresentation" and therefore the Commission relies on sellers with market-based rates to provide accurate and complete information to the Commission. Order at P 57, 63. This explanation, however, only further demonstrates the novelty of the Commission's position in this case. In *Enron*, the Commission revoked Enron's market-based rate authority after finding that Enron had engaged in gaming and misrepresentation related to the market. *Enron Power Mktg., Inc.*, 103 FERC ¶ 61,343, at P 53 (finding that Enron engaged in gaming in the form of inappropriate trading strategies), P 55 (finding that Enron failed to inform the Commission in a timely manner of changes in its market shares that resulted from its gaining influence/control over others' facilities), P 56 (concluding that Enron "engaged in behavior that undermines the functioning of the wholesale power market" and that "this same conduct violates the express requirements in [the Commission's] orders allowing the Enron Power Marketers to make sales at market-based

principled set of rules for when and how the Commission will exercise its authority to revoke market-based rates.

The principle that the punishment must bear at least some reasonable relationship to the behavior being punished is more important than the Commission's indignation in any particular case. JP Morgan may well face the loss of its market-based rate authority as a consequence of the pending investigation. But if so, it should be because of its conduct in the market, not because of a dispute over document production.

Accordingly, I would not reach in this proceeding the question of whether the statements violate section 35.41(b) of the Commission's regulations and would instead refer them to the ongoing investigation. Therefore, I respectfully dissent.

Cheryl A. LaFleur
Commissioner

rates that they report changes in their status.") (2003). Thus, in *Enron*, there was a clear nexus between Enron's conduct and its market-based rate authority, and the broad statements cited by the Commission today must be understood in that context.

EXHIBIT 4

ENERGY INSTITUTE AT HAAS

EI @ Haas WP 248

Market Impacts of a Nuclear Power Plant Closure

Lucas Davis and Catherine Hausman

Revised May 2015

http://ei.haas.berkeley.edu

Market Impacts of a Nuclear Power Plant Closure

Lucas Davis Catherine Hausman*

May 2015

Abstract

Falling revenues and rising costs have put U.S. nuclear plants in financial trouble, and some threaten to close. To understand the potential private and social consequences, we examine the abrupt closure of the San Onofre Nuclear Generating Station (SONGS) in 2012. Using a novel econometric approach, we show that the lost generation from SONGS was met largely by increased in-state natural gas generation. In the twelve months following the closure, natural gas generation costs increased by $350 million. The closure also created binding transmission constraints, causing short-run inefficiencies and potentially making it more profitable for certain plants to act non-competitively.

Key Words: Nuclear Power, Electricity Markets, Transmission Constraints, Carbon Emissions
JEL: L51, L94, Q41, Q54

*(Davis) Haas School of Business, University of California, Berkeley and NBER. Email: ldavis@haas.berkeley.edu. (Hausman) Ford School of Public Policy, University of Michigan and NBER. Email: chausman@umich.edu. An earlier version of this paper circulated under the title "The Value of Transmission in Electricity Markets: Evidence from a Nuclear Power Plant Closure." We thank Matt Barmack, Severin Borenstein, Jim Bushnell, Catherine Elder, Jeremiah Johnson, Ryan Kellogg, Erin Mansur, Shaun McRae, Nolan Miller, and seminar participants at Arizona State, Carnegie Mellon, Michigan State, MIT CEEPR, UC Energy Institute, UC Berkeley ERG, Illinois, Michigan, and Yale for valuable comments. We thank Mackenzie Humble for assistance assembling the price data from CAISO.

1 Introduction

Nuclear power has historically supplied a substantial portion of electricity – 20 percent in the United States and 14 percent worldwide for 2000 to 2012. As recently as 2008, the outlook for the industry was robust, with nuclear plants earning large profits. Since 2009, however, prospects for nuclear power – even at existing facilities – have substantially waned, with the closure of several large facilities and predictions of more closures to come (EIA 2014). As we describe in detail, multiple factors have contributed to the recent closures of nuclear plants. Peak wholesale electricity prices fell around 50 percent in real terms from 2007 to 2012,[1] a result of both falling natural gas prices and stagnant electricity demand. At the same time, costs for nuclear plants have been rising, a combination of rising wages and fuel prices, stricter safety regulations, and the aging of decades-old equipment.

To many observers, low profitability at *existing* nuclear plants is surprising, since the marginal cost of generation is very low at nuclear plants. However, while marginal costs hour-to-hour are low, fixed operating costs (e.g., keeping employees on staff) are high. Total operations and maintenance (O&M) costs at U.S. nuclear plants have increased by about 20 percent in real terms since 2002 and today are more than twice as high as O&M costs at natural gas plants. These higher costs reflect the fact that nuclear plants have substantially higher requirements for safety, security, and testing.

In this paper, we use evidence from a nuclear power plant closure to examine the rapidly evolving economics of nuclear power and to assess the potential private and social consequences of plant closures. While in operation, the San Onofre Nuclear Generating Station (SONGS) generated an average of 16 million megawatt hours of electricity annually, making it the second largest electric generating facility in California. During this period, SONGS generated enough electricity to meet the needs of 2.3 million California households[2] – about 8 percent of all electricity generated in the state. SONGS was closed abruptly in February 2012, when workers discovered problems with the plant's steam generators. Although it was not known at the time, SONGS would never operate again.

The first-order effect of the plant's exit was a large inward shift of the electricity supply curve. Like other nuclear power plants, SONGS produced electricity at very low marginal cost. Consequently, the plant was always near the bottom of the supply curve, operating around the clock and providing a consistent source of electricity. When SONGS was closed, this generation had to be made up for by operating other generating resources with higher marginal cost. We use rich micro-data from a variety of sources and a novel econometric

[1] Peak wholesale prices at various hubs for ICE contracts; source: EIA. Prices throughout are deflated to 2013 dollars using the GDP deflator.

[2] U.S. DOE/EIA "Electric Sales, Revenue, and Average Price," November 2013, Tables T1 and T2. California households used an average of 6.9 megawatt hours in 2012.

method to identify those marginal resources that would be expected to increase production. We find that the lost generation from SONGS was met largely by in-state natural gas plants. Bringing these additional plants online cost an average of \$63,000 per hour in the twelve months following the closure. The SONGS closure also had important implications for the environment, increasing carbon dioxide emissions by 9 million tons in the first twelve months. To put this in some perspective, this is the equivalent of putting 2 million additional cars on the road.[3]

There was also a second-order, but not insignificant, additional impact on the market. SONGS was even more valuable than these numbers suggest because of its location between Los Angeles and San Diego, two enormous demand centers. Although there is transmission that connects Southern California to the rest of the state, the capacity is limited. Prior to the closure, transmission capacity between Northern and Southern California was almost always sufficient, so that wholesale prices equalized in the two regions during the vast majority of hours. However, beginning with the closure in 2012, we document a substantial divergence in prices between Northern and Southern California. This binding transmission constraint and other physical constraints of the grid meant that it was not possible to meet all of the lost output from SONGS using the lowest cost available generating resources.

These second-order effects are reflected in our model as "residuals," measured as deviations from predicted plant behavior. We find that during low demand hours, the change in generation closely follows predictions based on pre-closure behavior, with about half of the increased generation coming from Southern California and the other half coming from Northern California. During high demand hours, however, we find significant residual effects: higher cost generating units coming online more than predicted. In high demand hours in 2012, we find that as much as 75 percent of the lost generation was met by plants located in Southern California. On average, these constraints increased generation costs by an average of \$4,500 per hour, implying that the total cost of additional natural gas generation was almost \$68,000 per hour in the twelve months following the closure.

These residuals also potentially reflect non-competitive behavior. Tight market conditions make it more profitable for certain firms to exercise market power, and using our model we are able to determine which individual plants changed their behavior the most after the SONGS closure. Because of the transmission constraints, the largest positive residuals are at Southern plants, and the largest negative residuals are at Northern plants. Surprisingly, we also find large negative residuals during high demand hours at two Southern plants: Alamitos and Redondo, both owned by the same company. This was unexpected but, as it turns

[3]According to U.S. DOE/EIA Annual Energy Review, September 2012, Table 2.8 "Motor Vehicle Mileage, Fuel Consumption, and Fuel Economy", light-duty vehicles with a short wheelbase use an average of 453 gallons of gasoline annually. For each gallon of gasoline, 19.6 pounds of carbon dioxide are emitted.

out, not coincidental. The Federal Energy Regulatory Commission recently alleged market manipulation at these plants over the period 2010 to 2012, for which JP Morgan paid fines of over $400 million. The fact that the results clearly identified these two plants suggests that our approach may serve as a useful diagnostic tool. Although a large residual effect does not prove that a plant is exercising market power, it is a good indicator of unusual behavior.

Overall, we find that the SONGS closure increased generation costs at other plants by $350 million during the first twelve months. This is a large change, equivalent to a 13 percent increase in total in-state generation costs. Annual O&M costs at SONGS were about the same amount, so the decision to close probably made sense from a private perspective. Incorporating externalities makes it less clear. Our estimates of the increase in carbon dioxide emissions imply external costs of almost $320 million during the first twelve months. If plant closure decisions are to be made efficiently, it is important that these environmental impacts be taken into account. Historically, state and federal policies aimed at decreasing carbon emissions have not been designed to incentivize nuclear plants.

Our paper contributes to several strands of the literature. Several recent papers have focused on the prospects for nuclear power, particularly as concern about climate change has increased (Joskow and Parsons, 2009; MIT, 2009; Davis, 2012; Joskow and Parsons, 2012; Linares and Conchado, 2013). However, the literature has almost exclusively focused on the outlook for *new* nuclear plants. The decision to enter the market is quite different from the decision to exit. Entry decisions are driven in large part by the large capital (and financing) costs of nuclear plants. In contrast, because these costs are sunk for existing nuclear plants, exit decisions are driven by wholesale electricity prices and operating expenses. With construction of new nuclear almost completely halted, we argue that exit will be the more policy-relevant margin for the foreseeable future.

Our paper also adds to a small literature on the value of geographic integration in electricity markets (Mansur and White, 2012; Birge et al., 2013; Wolak, 2014*a*; Ryan, 2014). Economists have long written about the importance of transmission constraints, but previous studies have either used stylized theoretical models (Cardell, Hitt and Hogan, 1997; Joskow and Tirole, 2000), or Cournot simulations (Borenstein, Bushnell and Stoft, 2000; Ryan, 2014), rather than econometric analysis. Our methodology is novel, because it quantifies the impact of transmission constraints without requiring strong assumptions about the firms' objective function or an explicit representation of the physical constraints of the electric grid. While our estimates are not directly applicable to other markets, we see broad potential for applying this general method elsewhere. Our approach relies entirely on publicly-available data, so it would be relatively straightforward to perform similar analyses in other markets, both for quantifying the impacts of large changes in generation and transmission infrastructure, and for detecting unusual changes in firm behavior.[4]

2 Background

2.1 Economic Outlook for Existing Nuclear Plants

In the United States, electricity generation in 2012 came from coal (37%); natural gas (30%); nuclear (19%); hydro (7%); and wind, solar and other renewables (5%).[5] The global generation mix was qualitatively similar: fossil fuels (67%); nuclear (11%); hydro (17%); and wind, solar, and other renewables (5%).[6] This mix of technologies reflects marginal and fixed cost considerations, flexibility, and environmental objectives. The lowest marginal cost sources are solar and wind, followed by nuclear, and then by fossil fuel plants. Coal tends to have lower marginal cost than natural gas; but in recent years, falling natural gas prices in North America have pushed some natural gas plants ahead of coal plants in the queue (Cullen and Mansur, 2014; Holladay and LaRiviere, 2014; Linn, Muehlenbachs and Wang, 2014).

Despite the low marginal cost of nuclear plants, their profitability and long-term viability have eroded substantially since 2009 in the United States (EIA 2014). Four nuclear plants have recently closed: Crystal River, Kewaunee, San Onofre, and Vermont Yankee. Moreover, recent reports have flagged numerous additional plants that are at risk of closing (Navigant Consulting Inc, 2013; UBS, 2013, 2014). One report provided the following summary: "Nuclear units, with their high dispatch factors have among the greatest exposure to gas/power price volatility, as they are price takers. In tandem, nuclear generators have continued to see rising fuel and cost structures of late, with no anticipation for this to abate" (UBS, 2013). As a result of these concerns, the EIA assumes 6 GW of nuclear retirements by 2019 in the reference case for its 2014 Annual Energy Outlook.

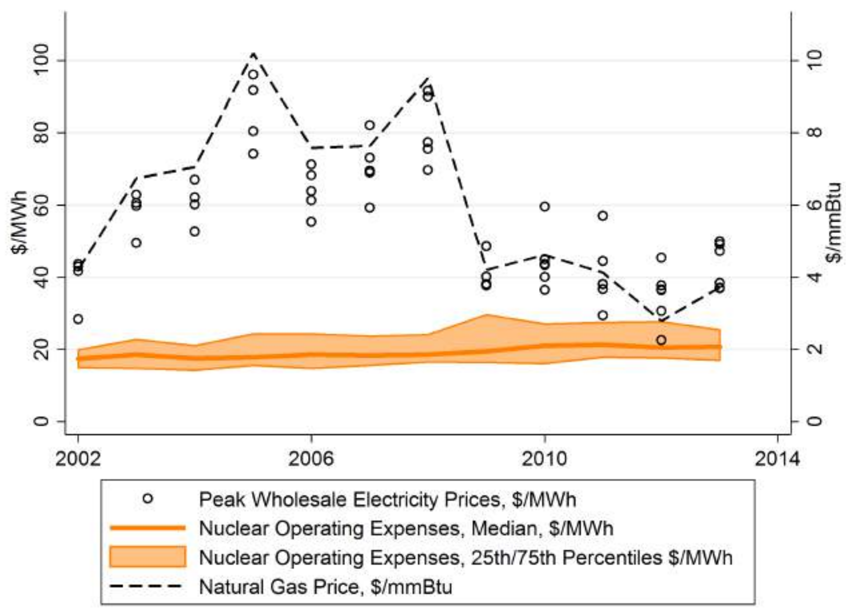
Figure 1 describes this erosion of profitability, showing in real terms both rising costs (solid orange line) and falling wholesale electricity prices (hollow circles, for peak prices). Even during peak hours, nuclear plants are currently earning only modest net revenues. The primary driver has been a dramatic decrease in wholesale electricity prices. This is a direct consequence of the fall in natural gas prices (the dashed line in Figure 1) driven by the shale boom. The advance of technologies for extracting unconventional natural gas caused an almost

[4]Such large changes are not uncommon. For instance, the current California drought has led to hydroelectric generation levels in 2014 that are over one million MWh per month lower than the 2005-2013 averages, a drop roughly equal to the loss in generation from SONGS. As another example, Germany has closed 6 of 17 nuclear power plants (6.3 total gigawatts) since the Fukushima accident in March 2011 (Grossi, Heim and Waterson, 2014).

[5]Table 7.2a "Electricity Net Generation: Total (All Sectors)" in EIA (2013b).

[6]EIA's International Energy Statistics, 2012.

Figure 1: Declining Profitability of U.S. Nuclear Power Plants



Note: This figure plots wholesale peak electricity prices in real \$/MWh at various ICE hubs around the country. The dashed black line shows Henry Hub natural gas prices (in \$/mmBtu), the driver of wholesale peak electricity prices. The orange lines show the mean, 25th percentile, and 75th percentile operating expenses at U.S. nuclear plants, in real \$/MWh. Electricity and natural gas prices are from EIA; operating expenses are from EUCG, Inc.

50 percent decline in natural gas prices in the United States from 2007 to 2013 (Hausman and Kellogg, 2015). Natural gas power plants are frequently on the marginal portion of the supply curve, so their marginal costs tend to set wholesale electricity prices. Moreover, as we show below, marginal costs for natural gas plants are predominantly fuel costs. Accordingly, not only are natural gas plants pushing ahead of coal plants in the supply queue, they are also pushing down wholesale electricity prices.[7] The magnitude of the pass-through, empirically estimated in Linn, Muehlenbachs and Wang (2014), is determined by the heat rates of marginal plants.

Two additional factors help explain this period of sustained low wholesale electricity prices. First, there has been a rapid rise in renewables capacity. Non-hydro renewables grew by over 250 percent from 2001 to 2013, albeit from a small baseline. Second, electricity demand has been largely stagnant. While growth averaged almost 4 percent per year from 1970 to 1990, from 2000 to 2014 it averaged less than 1 percent per year,[8] and it is expected to continue to

[7]The figure plots peak wholesale prices, using annual averages of daily prices for ICE contracts at the MISO (Indiana Hub), PJM (West), CAISO (NP-15), Northwest (Mid-Columbia), CAISO (SP-15), and Southwest (Palo Verde) hubs. The year-to-year variation largely reflects changing natural gas prices. The geographic dispersion reflects transmission constraints in electricity combined with pipeline constraints in natural gas and differences in heat rates at natural gas plants.

[8]U.S. DOE/EIA "Table 7.6 Electricity End Use," April 2015.

be less than 1 percent per year (EIA 2015). As a result of falling natural gas prices, growing renewables capacity, and stagnant demand, both peak and off-peak electricity prices fell by around 50 percent in real terms from 2007 to 2012.[9]

At the same time that revenues have fallen, multiple factors have contributed to rising costs at nuclear power plants. Costs can be divided into three categories: (1) capital costs, (2) fuel costs, and (3) operating expenses. Capital costs are largely sunk, and therefore not relevant for our analysis. Fuel costs per MWh, however, increased in real terms by 25 percent from 2002 to 2012, concurrent with an increase in uranium prices.[10] Operating expenses have also increased 18 percent in real terms from 2002 to 2012 at the median plant.[11] Part of this increase has come from rising labor costs. According to data from the Bureau of Labor Statistics' *Quarterly Census of Employment and Wages*, average annual salaries in the nuclear electric power generation sector (NAICS 221113) increased by 21.5 percent in real terms between 2002 and 2013. Possible additional factors include new safety requirements following Fukushima and the aging of U.S. reactors. In 2014, the age of U.S. nuclear power reactors ranged from 19 to 46 years, and the average age was 35.

Figure 1 shows that operating expenses at U.S. nuclear plants have increased steadily since 2002. This is true whether one looks at the median, 25th, or 75th percentile. These expenses include operations and maintenance costs, such as labor costs, but not fuel costs or capital expenditures. A substantial wedge between peak wholesale prices and operating costs can be seen in the early 2000s, but by 2009 the wedge was dramatically shrunk. Moreover, the actual wedge between revenues and costs is even lower than what is shown in this figure. Off-peak wholesale electricity prices are also relevant, and are around 35 percent lower than on-peak prices. Fuel costs also reduce the wedge; in 2012 they were around \$7–8 per MWh (source: EIA Table 8.4, and SNL). Unfortunately, we do not have a comprehensive time series of nuclear fuel costs.

The figure makes clear that U.S. nuclear power plants have become much less profitable. Nuclear plants continue to have lower marginal cost than coal and gas plants and thus are still

[9] In addition to the peak prices for ICE contracts available from EIA, we assembled data from SNL Financial from 6 different wholesale hubs: ERCOT (North), New England ISO (Massachusetts Hub), PJM (West), Southwest (Palo Verde), Northwest (Mid-Columbia), and MISO (Illinois Hub). Off-peak prices generally run from about 11pm to 7am, though the exact hours vary across ISO. In both 2007 and 2012, off-peak prices averaged around 65 percent of peak prices.

[10] Source: EIA, "Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 2002 through 2012." Data are not available for independent power producers, but fuel costs are presumably similar as all plants purchase fuel assemblies in the same market.

[11] Source: EUCG, Inc. EUCG assembles blinded cost data from all nuclear power plants in the U.S. for cross-reactor information sharing. These data are not publicly available, but we were provided with summaries by quartiles after making a data request. Other sources of information on operating costs include FERC and EIA, which only collect data on a subset of plants, or SNL, which extrapolates the FERC data to other plants. The EUCG data, which represent *all* plants, are in line with FERC and SNL summaries.

near the bottom of the supply curve. Instead, what has changed is the ability of hour-to-hour net revenues to cover the fixed costs of keeping a nuclear plant open. Of course, all types of electric-generating facilities must be able to cover their ongoing fixed costs, but this is particularly relevant for nuclear power plants because of their high O&M costs. Table 1 shows fuel and O&M costs at nuclear plants compared to other forms of generation. Nuclear plants have by far the lowest fuel cost. However, O&M costs are $15.8/MWh at nuclear plants, compared to $3.9–$9.4/MWh at fossil-fuel plants.[12] Natural gas combined cycle plants, in particular, have O&M costs that are only about 1/4th that of nuclear plants.

Although in the table we have expressed O&M costs scaled by generation, this should not in general be thought of as a marginal cost. With O&M, it is difficult to sharply distinguish between fixed and marginal costs; the former consists of costs that allow a plant to remain open, but do not depend on the level of generation produced. These include, for instance, employees whose primary task is safety compliance. In Table 1, we do not attempt to distinguish the two types of O&M. What is most noteable, however, is how much higher O&M costs are at nuclear plants relative to coal and natural gas plants. As such, fuel makes up less than 35 percent of operating expenses for nuclear plants, while it makes up over 75 percent at coal and natural gas plants.

The table makes clear that the economics of running a nuclear plant are quite different from the economics of running a coal or natural gas plant. While low fuel costs mean that nuclear plants should be continually operating conditional on being open, high O&M costs mean that even running 365 days per year may not generate enough revenue if wholesale prices are low. These high O&M costs are not sunk in the way that capital costs are; they can be avoided if a plant closes, and indeed you would expect a plant to close when O&M costs exceed expected net revenue.[13]

2.2 The San Onofre Nuclear Generating Station

San Onofre Nuclear Generation Station (SONGS) is a retired two-reactor, 2,150 megawatt nuclear power plant, operated by Southern California Edison (SCE).[14] Trouble for SONGS started on January 31, 2012 when operators detected a small leak inside one of the steam generators. The reactor with the leak was shut down immediately. At the time this occurred, the other reactor had already been shut down for three weeks for a routine refueling outage.

[12] Average nuclear O&M costs are somewhat higher in EUCG data, but this is largely a function of weighting by generation. The unweighted average O&M costs in the SNL data are $20.4/MWh for 2013, compared to $20.9/MWh in the EUCG data.

[13] An additional cost, required by the NRC, is the decommissioning of a site after closure. The NRC requires funds for decommissioning in advance, for instance through a trust fund or other surety method.

[14] SCE is also the majority owner (78%). The other owners are San Diego Gas & Electric (20%) and the city of Riverside (2%).

Table 1: Fuel Costs and Operating Expenses by Electric Generating Technology, 2013

	Fuel, \$/MWh	O&M, \$/MWh	Fuel plus O&M, \$/MWh
Nuclear (n=99)	8.2	15.8	24.0
Coal (n=1074)	25.2	7.9	33.1
Natural Gas Combined Cycle (n=1764)	32.6	3.9	36.6
Natural Gas Combustion Turbine (n=2083)	41.7	9.4	51.1

Source: Authors' calculations based on data from SNL Financial's "Generation Supply Curve." The table reports mean fuel and operating costs per megawatt hour, weighted by net generation. Means are calculated over all generating units that were operating in the continental United States in 2013.

Although it was not known at the time, neither reactor would ever operate again. On investigation, it was discovered that thousands of tubes in the steam generators in both units were showing premature wear. This was followed by months of testing and, eventually, a proposal to the Nuclear Regulatory Commission (NRC) to restart one of the units at reduced power level. An additional eight months passed without a decision from the NRC. Meanwhile, policymakers grew concerned that without SONGS, the grid would face "additional operational challenges in the Los Angeles Basin and San Diego areas" (CEC 2012), relating to the possibility of insufficient summer capacity and the possibility of transmission constraints (CAISO 2012; NERC 2012).

Facing uncertainty about the NRC ruling, and continued costs of maintaining SONGS in a state of readiness, SCE made the decision in June 2013 to permanently retire the facility. "SONGS has served this region for over 40 years," explained Ted Craver, Chairman and CEO, "but we have concluded that the continuing uncertainty about when or if SONGS might return to service was not good for our customers, our investors, or the need to plan for our region's long-term electricity needs" (Southern California Edison, 2013).

The SONGS closure was abrupt, permanent, and unexpected; this allows us to sharply distinguish between the before and after periods, and thus to identify the effect of the closure. In contrast, in many empirical settings, openings and closings of transmission and generation capacity are both expected and endogenous, so that causal effects are difficult to identify. Moreover, outages at transmission and generating facilities are potentially endogenous, as they are more likely to occur when stress is being put on the system. There is some precedent for studying changes in market behavior during changes in nuclear plant operations. In particular, Wolfram (1999) instruments for wholesale electricity prices using available nuclear capacity, exploiting the large quasi-random changes in electricity supply due to unplanned outages. Our study is different in that we focus on a permanent shock rather than temporary outages, but the identifying variation is similar. In other related work, Allcott, Collard-

Wexler and O'Connell (2014) use exogenous changes in electricity supply from variation in hydro generation to study how shortages affect productivity in India.

SONGS is of additional interest because, like many U.S. nuclear power plants, it operated in a deregulated electricity market. In contrast, in states where generation companies are regulated using cost-of-service regulation there is less scope (and less incentive) for companies to exercise market power in response to changes in market conditions. In line with this, the SONGS closure is noteworthy because it evokes parallels with the California electricity crisis. The year 2012 was similar to 2000 in that both years were unusually dry, resulting in low levels of hydro generation. Removing an enormous generation source like SONGS, particularly during a bad year for hydroelectric generation, might have been expected to create tight supply conditions like in 2000. As it turns out, however, market prices and other outcomes in 2012 were very different from the experience in 2000. We think that comparing the behavior of the market in 2012 to 2000 can yield insights, both about firm behavior and market design.

Finally, the SONGS setting is worth studying because it cleanly demonstrates the importance of accounting for transmission congestion. SONGS was valuable to the California market not just because it generated a large amount of generation, but also because of its prime location. Located in the Northwest corner of San Diego County, SONGS provided electricity in the highly-populated corridor between Los Angeles and San Diego, where there are few other large power plants and where transmission is limited. Transmission constraints are a pervasive feature of electricity markets, and they are extremely important because unlike most other goods, electricity cannot be cost-effectively stored. Supply must meet demand at all times, or the frequency in the grid will fall outside of a narrow tolerance band, causing blackouts. With electricity demand highly variable and inelastic, the market clears mostly on the supply side. Geographic integration helps smooth the price volatility that can result. As we document, the abrupt SONGS closure caused transmission constraints to bind. In contrast, previous planned outages were carefully scheduled in low-demand periods to avoid this possibility.

3 Data

For this analysis we compiled data from a variety of different sources including the U.S. Department of Energy's Energy Information Administration (EIA), the California Independent System Operator (CAISO), and the U.S. Environmental Protection Agency (EPA). As we mention in the introduction, a strength of our analysis is that it relies entirely on publicly-available data.

3.1 Generation Data from EIA

We first assembled a dataset of annual plant-level electricity generation from the EIA's *Power Plant Operation Report* (EIA-923). This is a required survey for all U.S. electric generating facilities with more than one megawatt of capacity. The advantage of these data is that they are comprehensive, including not only large fossil-fuel generating units, but also smaller and less frequently operated units, as well as hydroelectric facilities, solar and wind plants, and nuclear plants. Most California plants complete the survey only once per year, so we perform all analyses of the EIA-923 data at the annual level, relying on the other datasets listed below for within-year comparisons. These data also contain information on plant characteristics, including operator name, fuel type, and some details about the generation technology. We supplement these characteristics with additional information (county, capacity, and vintage) from another Department of Energy dataset, the *Annual Electric Generator Report* (EIA-860).

Table 2 describes California electricity generation in 2011 and 2012. Overall the California generation portfolio is substantially less carbon intensive than the rest of the United States, with more emphasis on natural gas, hydro, and renewables. By far the largest source of generation is natural gas, with 44 percent of total generation in 2011. The second largest source is hydro, accounting for 21 percent of generation. The two nuclear plants, San Onofre and Diablo Canyon, each contributed approximately 9 percent of total generation in 2011. Finally, geothermal, wind, solar, and other renewables account for about 13 percent of total generation. Additional details are provided in the Online Appendix.

SONGS was closed on January 31, 2012, so the columns in Table 2 can be approximately interpreted as before and after the SONGS closure. Panel A reports average monthly generation by fuel type. Nuclear generation decreased by 1.5 million megawatt hours monthly; this matches the drop in generation expected given the SONGS hourly capacity of 2,150 MW. The table also shows, however, that 2012 was a relatively bad year for hydroelectric power, with a decrease of 1.3 million megawatt hours monthly. Thus the year-on-year decrease in hydroelectric generation is almost as large as the lost generation from SONGS. Offsetting these decreases, natural gas generation in California increased by 2.6 million megawatt hours monthly. There is also a modest increase in wind generation, and close to zero changes for all other categories.

Panel B examines natural gas generation more closely. These categories primarily distinguish between whether plants are owned by electric utilities or independent power producers, and whether or not the plants are cogeneration facilities. The two largest categories are "Independent Power Producer Non-Cogen" and "Electric Utility." Both increase substantially in 2012. Generation is essentially flat in all other categories between 2011 and 2012. In some cases (e.g. industrial non-cogen) there are large percentage changes but from a small base

Table 2: California Electricity Generation, 2011-2012

	Average Monthly Generation, Million MWh 2011	Average Monthly Generation, Million MWh 2012	Change
Panel A: By Generation Category, EIA Data			
Natural Gas	7.41	9.97	2.56
Wind	0.65	0.81	0.17
Solar (PV and Thermal)	0.07	0.12	0.04
Other Renewables	0.50	0.53	0.02
Geothermal	1.05	1.04	0.00
Coal	0.17	0.11	-0.05
Other Fossil Fuels	0.29	0.22	-0.08
Hydroelectric	3.54	2.28	-1.25
Nuclear	3.06	1.54	-1.51
Panel B: By Type of Natural Gas Plant, EIA Data			
Independent Power Producer Non-Cogen	2.63	4.48	1.85
Electric Utility	2.24	2.98	0.73
Industrial Non-Cogen	0.03	0.11	0.07
Commercial Non-Cogen	0.02	0.02	0.00
Commercial Cogen	0.14	0.13	-0.01
Independent Power Producer Cogen	1.37	1.36	-0.01
Industrial Cogen	0.99	0.90	-0.09
Panel C: By Generation Category, CAISO Data			
Thermal	6.12	8.47	2.35
Imports	5.45	5.77	0.32
Renewables	2.11	2.25	0.14
Large Hydroelectric	2.47	1.58	-0.89
Nuclear	3.07	1.55	-1.51

Note: This table reports the average monthly net electricity generation in California in 2011 and 2012, measured in million MWh. As described in the text, the EIA data describe all U.S. generating facilities with more than one megawatt of capacity. We include generation from all facilities in California. In Panel A, "Other Renewables" includes wood, wood waste, municipal solid waste, and landfill gas. "Other Fossil Fuels" includes petroleum coke, distillate petroleum, waste oil, residual petroleum, and other gases. Panel C describes electricity sold through the California Independent System Operator, including four categories of generation from inside California, and "imports" which includes all electricity coming from out of state.

level. It is difficult to make definitive statements based on these aggregate data, but this is consistent with plants in these other categories being much less able to respond to market conditions. With industrial, commercial, and cogeneration facilities, electrical output is a joint decision with other processes (e.g. oil extraction or refining, steam production, etc.), which limits the ability of these plants to respond quickly to changes in market conditions.

3.2 Generation Data from CAISO

To complement the EIA data, we next assembled a database using publicly-available records from CAISO. About 90 percent of the electricity used in California is traded through CAISO. All of California's investor-owned utilities and most municipally-owned electric utilities buy power through CAISO. An important exception is the municipally-owned Los Angeles Department of Water and Power (LADWP), which maintains its own electricity generation and also imports power from other states through long-term contracts.

The data from CAISO describe hourly electricity generation by broad categories (thermal, imports, renewables, large hydroelectric, and nuclear). The renewables category is disaggregated into six subcategories (geothermal, biomass, biogas, small hydroelectric, wind, and solar). See CAISO (2013c) for details. Table 2, Panel C describes generation by category in 2011 and 2012. These data corroborate the general pattern observed in the EIA data. From 2011 to 2012, there is a large increase in thermal generation and large decreases in nuclear and hydroelectric generation.

An important advantage of the CAISO data is that they also track imports. Between 2011 and 2012 imports increased from 5.45 to 5.77 million megawatt hours monthly. This is a substantial increase, but it offsets less than 1/5th of the shortfall experienced from the SONGS closure, and only about 1/10th of the combined shortfall from SONGS and the decrease in hydroelectric generation. We examine the role of imports in greater depth in Section 5.1, but both the EIA data and CAISO data suggest that California thermal generation played the primary role in making up for the lost generation from SONGS.

3.3 Generation Data from CEMS

We next built a database of hourly emissions, heat input, and electricity generation by generating unit using the EPA's Continuous Emissions Monitoring System (CEMS). The CEMS data contain these hourly data as well as descriptive information for each generating unit, including owner name, operator name, technology, primary and secondary fuel, and vintage. Finally, we match each generating unit to one of the three price locations (South, Central, and North) using the "Control Area Generating Capability List" from CAISO (2013d).

CEMS data have been widely used in economic studies of generator behavior because they provide a high-frequency measure of generation at the generating unit level. See, e.g., Joskow and Kahn (2002); Mansur (2007); Puller (2007); Holland and Mansur (2008); Cullen (2013); Cullen and Mansur (2014); Graff Zivin, Kotchen and Mansur (2014); Novan (Forthcoming). CEMS data are highly accurate because facilities must comply with specific requirements for maintenance, calibration, and certification of monitoring equipment, and because the methodology used for imputing missing data creates an incentive for generating units to keep monitoring equipment online at all times.

During our sample period, 107 plants in California report to CEMS.[15] In 2011, these plants represent 30 percent of total generation in California and 62 percent of total natural gas generation. This relatively low fraction of generation covered by CEMS reflects that a large share of California generation comes from nuclear, hydro, and renewables – none of which are in CEMS. In addition, as discussed above, one third of natural-gas fired generation in California is from cogeneration, industrial, and commercial facilities, which are generally not in CEMS. Indeed, generation reported in CEMS in 2011 is 96 percent of non-cogen natural gas-fired generation by electric utilities and independent power producers reported in the EIA data.

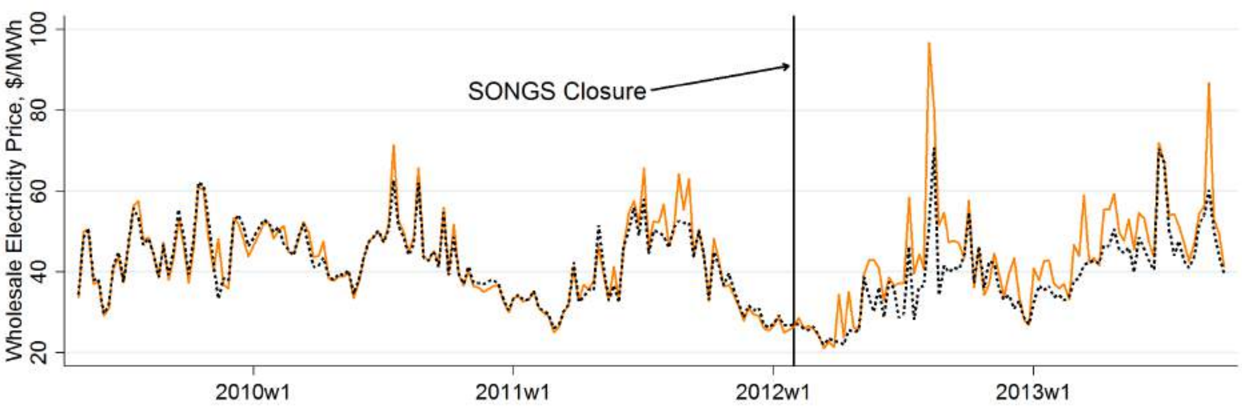
Despite the incomplete coverage, the CEMS data are extremely valuable. They cover the largest thermal plants and the plants that are best able to respond to market changes, in addition to being the only publicly available information on hourly, generating unit-level outcomes. Moreover, by combining the CEMS data with EIA and CAISO data, we are able to get a sense of how much our results might be affected by focusing exclusively on CEMS generating units. Table A2 in the Online Appendix lists the largest plants that do not appear in CEMS. Overall, these plants tend to be quite small, or to be types of facilities (e.g. cogeneration plants, industrial facilities) that are not able to respond quickly to market changes. We empirically examine the responsiveness of these units below.

While CEMS data describe gross generation, for this analysis we would ideally observe net generation. The difference between the two is equal to "in-house load," which is the electricity the plant uses to run, for instance, cooling equipment or environmental controls. As such, net generation is what is sold on the grid. Reliable plant-level or unit-level estimates of the ratio between net and gross generation are not available. In the analyses that follow we use an implied measure of net generation, which we calculate as 95.7 percent of gross generation. This 4.3 percent difference is the median difference in our sample between net generation from EIA and gross generation from CEMS, after dropping some outliers.[16] Kotchen and Mansur (2014) make a similar comparison using national data, finding a 5-percent mean difference.

[15] CEMS reporting requirements do not change during our sample period.

[16] Specifically, we examine generation data for 2005-2011 plants that appear in both CEMS and EIA. We calculate the annual net to gross ratio for each plant, using net generation as reported to EIA and gross generation as reported to CEMS. The median ratio is 0.966, but there are implausible outliers, such that the average is greater than 1. In particular, if some but not all generating units report to CEMS, this ratio can appear larger than 1. Dropping these outliers, the median is 0.957 and the average is 0.926. While we assume a 4.3 percent difference for our main specifications, results are similar using 2.15 percent or 8.6 percent.

Figure 2: Evidence of Increasing Transmission Constraints since 2012



Note: This figure was constructed by the authors using data on California wholesale electricity prices from CAISO. The figure plots average weekly prices at 3 pm between May 2009 and September 2013, in $2013/MWh. Weekends are excluded. The dashed black line is for Northern California (NP15), and the solid orange line is for Southern California (SP26). The vertical line indicates January 31, 2012, the day the second SONGS unit was shut down.

3.4 Wholesale Price Data

We also obtained hourly wholesale electricity prices from CAISO. We use prices at three locations: NP15 (Northern California), ZP26 (Central California), and SP26 (Southern California). Figure 2 plots prices in Northern and Southern California in dashed black and solid orange lines, respectively. We plot prices for 3 p.m. on weekdays (averaged across the week), a time when transmission constraints are more likely to bind. Before the SONGS closure, prices track each other extremely closely, with no price differential in most weeks. After the SONGS closure, there are many more weeks with positive differentials, including a small number of weeks with differentials that exceed 50 percent of the North price.

4 Empirical Strategy and Generation Regressions

4.1 Creating a Credible Counterfactual

Our objective is to determine which power plants increased generation to make up for the 2,150 megawatts of capacity that became unavailable when SONGS closed in February 2012. Although at first glance this might appear to be a relatively straightforward exercise, simple before-and-after comparisons would not be credible. There were several significant changes to the market between 2011 and 2012. For example, as we showed earlier, hydroelectric generation was low in 2012. These changes make it difficult to interpret before-and-after comparisons like our Table 2.

One potential approach for inferring the causal impact of the SONGS closure would have been to use a regression-discontinuity (RD) research design, comparing generation immediately before and after the SONGS closure. This approach has a great deal of intuitive appeal, but it would only be useful for estimating a very short-run effect, i.e. changes in generation during the days or weeks following the closure. Although this is somewhat interesting, we are much more interested in longer-run changes in generation patterns. In particular, we want to be able to examine June, July and August 2012, when air-conditioning and other factors lead electricity consumption in California to reach its annual peak. The RD approach is not helpful for examining this peak period because it occurs several months after the closure.

Instead, the approach we adopt in this paper is to construct an econometric model of the relationship between system-wide demand and unit-level generation, and then to use this model to quantify changes in generation post closure. The basic idea is simple. System-wide demand varies substantially hour-to-hour as a function of weather and economic activity. Low-cost generating units operate most hours of the year, regardless of system-wide demand, while higher-cost generating units operate only during relatively high demand hours. The first thing we do is describe this relationship semi-parametrically, using a series of regressions, estimated separately before and after the closure. For our main results, we focus on system-wide demand net of generation from non-thermal sources. This prevents our estimates from being biased by the low hydroelectric generation in 2012 or other confounding factors.

As we described briefly in the introduction, we distinguish between two effects: (1) the predicted change in generation associated with the next generating units along the marginal cost curve being brought online; and (2) the residual change in generation associated with a change in the order of the generating units along the supply curve. The predicted effects, which vary from hour to hour, measure a non-marginal shift (arising from the loss of SONGS) in the net demand faced by each generating unit. Residual effects measure differences between actual generation and predicted generation. While residual changes could result from differential changes in marginal costs or from the exercise of market power, the primary explanations for residual changes in our application are transmission constraints and other physical limitations of the grid.

An alternative to our empirical strategy would have been to simulate counterfactuals using an engineering model of the electrical grid combined with a structural model of firm optimization. Although these models have been widely used, our method is better suited to the application we consider for several reasons. First, while Cournot simulations have been used to study two-node transmission problems, the transmission constraints in our application are more complex. In addition to congestion between the two main North and South zones, congestion *within* regions is also important. And while engineering models exist that attempt to capture these features (e.g. GE-MAPS), they assume more information than market participants actually have, and they rely on simplifying assumptions that do not reflect changing grid conditions (Barmack et al., 2006). In practice, electric grid system operators use a combination of output from such models and real-time information about system conditions.

Performing counterfactual simulations would also require strong assumptions about generator and system operator behavior. While the objective function for independent power producers is relatively clear, describing behavior by investor-owned utilities is more difficult because they are subject to rate-of-return regulation. System operator behavior is important as well. During this period, CAISO was actively implementing new automated bid mitigation procedures and increasing the use of exceptional dispatches (CAISO 2013b).[17] Modeling these rapidly evolving market practices explicitly poses real challenges and would have required not only imposing these constraints in the model but also making strong assumptions about generators' expectations about these practices.

4.2 Generation Regressions by Category

The core of our econometric model is a system of what we call "generation regressions," which describe the relationship between system-wide demand and generation at individual sources. We estimate these regressions first for broad categories of generation and then later, in Section 4.3, for individual generating units. For the generation regressions by category the estimating equation takes the following form:

$$generation_{it} = \sum_{b} \left(\gamma_{bi} \cdot \ \mathbb{1}\{system\text{-}wide\ demand_t = b\}\right) + \varepsilon_{it}. \tag{1}$$

The dependent variable is electricity generation for category i in hour t, measured in megawatt hours. We use the categories reported in CAISO data: thermal, large hydro, imports, nuclear, and renewables. In addition, we separate thermal into generation that appears in CEMS and generation that does not, where the latter is calculated as the difference between thermal generation reported by CAISO and thermal generation reported by CEMS.

The only independent variables in the regression are a set of indicator variables corresponding to different levels of total system demand.[18] We divide system-wide demand into bins of equal width, indexed by b. For convenience, we define the bin width as $2{,}150/2 = 1{,}075$ megawatt hours, so that we can assume that system demand increased by two bins following the SONGS closure. We have experimented with alternative bin widths, and the results are similar with both more and fewer bins.

[17]Bid mitigation is the replacement of submitted bids with default cost-based bids; exceptional dispatch is a manual override of the market optimization algorithm.

[18]We have estimated several alternative models that include fixed effects, such as: (i) hour-of-day effects, (ii) month-of-year effects, and (iii) hour-of-day interacted with month-of-year effects. These could control for plant utilization that varies by time of day or by season. Results are very similar across specifications, indicating that these fixed effects add little to our preferred specification with flexible system-wide generation.

At first glance, this estimating equation would appear to suffer from simultaneity. However, electricity demand is both highly inelastic and highly variable across hours. In our sample, peak demand is routinely 150 to 200 percent of off-peak demand, and there is, in addition, enormous seasonal variation in demand driven by lighting and air conditioning. In practice, these exogenous shifts in demand overwhelm cost shocks and other supply-shifters in determining equilibrium quantities.

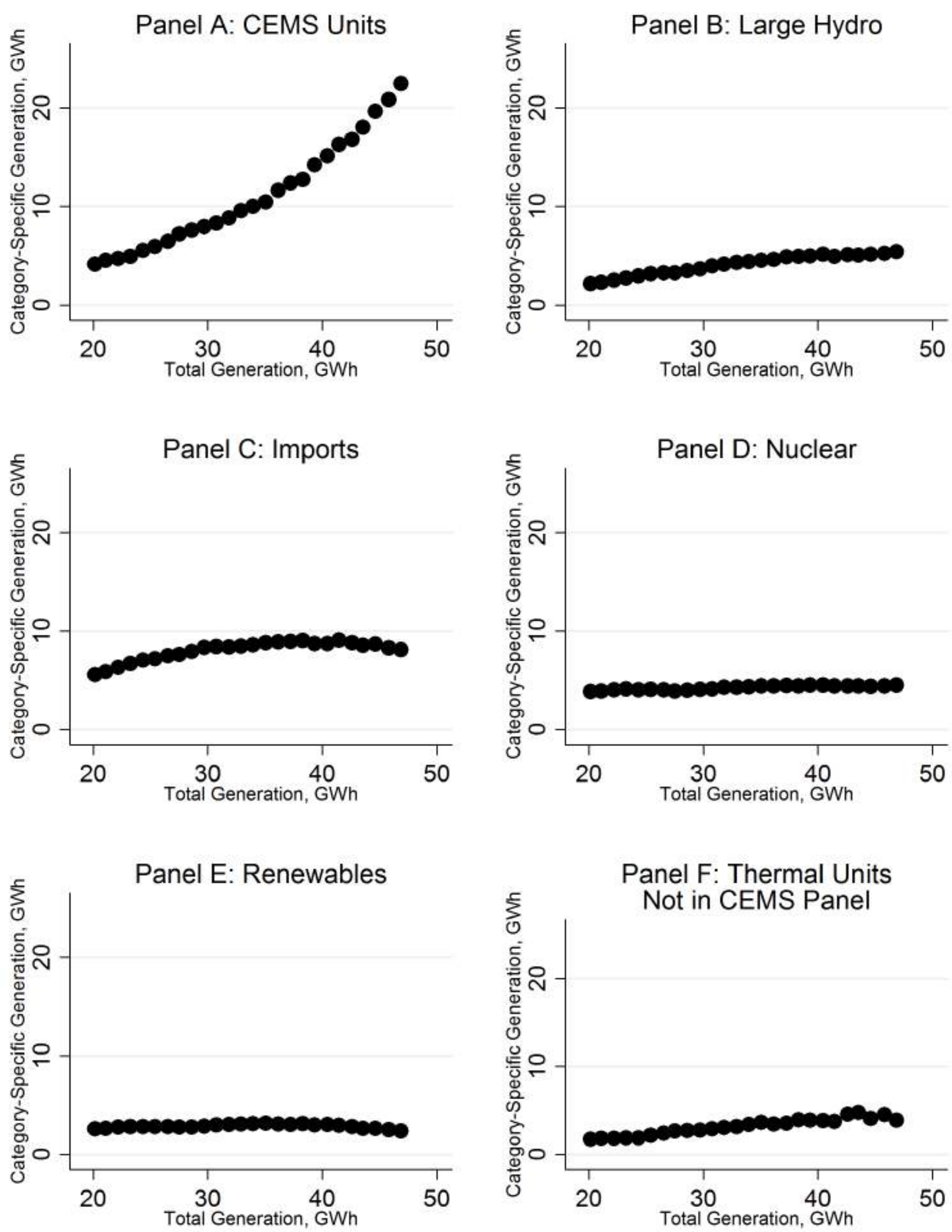
We do not include a constant in the regression, as the indicator variables sum to unity. We could equivalently drop one indicator variable and interpret the coefficients relative to the excluded bin, but our approach makes it easier to interpret the estimated coefficients. Without including a constant, the coefficients γ_{bi} are equal to the average generation for category i when system demand is in bin b. If there were no dynamic dispatch considerations and no plant outages, this coefficient would be equal to zero up until the point when lower-cost generating units had already been turned on to meet demand, and then would be equal to the unit's capacity.

We estimate equation (1) using hourly data from 2010 through January 31, 2012, the two years leading up to the SONGS closure. We begin the sample on April 20, 2010 because hourly CAISO generation data are not available from before that date. Additionally, we drop a small number of days (fewer than ten) for which data from CAISO are incomplete. Because the coefficients γ_{bi} are allowed to differ by generation category, we estimate six separate regressions, one for each category. Figure 3 plots the estimated coefficients. In all plots, the x-axis is total generation from all sources, divided into bins. The y-axis is average source-specific generation in MWh. We plot all six categories using the same scale for the y-axis, so that one can immediately compare both the level and responsiveness of generation.

The CEMS units (Panel A) are very responsive across all quantiles of demand. Large-scale hydro (Panel B) is only somewhat responsive, which is a bit surprising given the potential for using large hydroelectric facilities to follow demand fluctuations.[19] We thought this might be because 2011 had relatively high water supply, so we also examined the generation regression for 2012. Though the overall level of hydro generation is lower in 2012, the slope is about the same. Imports (Panel C) are also somewhat responsive, but only for relatively low demand hours. This pattern is consistent with Bushnell, Mansur and Saravia (2008), which emphasizes results from a linear-log specification implying low import responsiveness during high demand hours. Past the median level of demand, imports are essentially flat. As we describe in the Online Appendix, this could result from correlated demand across states or from interstate transmission constraints. Nuclear (Panel D) and renewables (Panel E) are not responsive, as expected – the nuclear unit (Diablo Canyon) is baseload, and renewable generation is

[19]However, hydro operators are subject to minimum and maximum flow constraints.

Figure 3: Generation Regressions by Category



Note: These figures plot the coefficients from six separate regressions. As described in detail in the text, these regressions are estimated using hourly data from April 20, 2010 until January 31, 2012. The x-axis is total generation from all sources, including imports, and the y-axis is average generation, in MWh, for that category of generation. For the non-CEMS thermal units in Panel F, we have subtracted total CEMS generation in our balanced panel from total thermal generation as reported by CAISO. The 95 percent confidence intervals are not shown, because they are extremely narrow for all six panels.

exogenously determined by weather. Thermal units not in the CEMS data (Panel F) are also not very responsive, reflecting that they are primarily cogeneration and industrial facilities.

It is interesting to compare these results with the aggregate pattern of generation in Table 2. Both show, in some sense, the ability of different generation sources to respond to changes in demand, albeit on very different time scales. The year-to-year comparison suggests that the majority of the response to the SONGS closure came from natural gas generation, and this is consistent with the hour-to-hour responsiveness observed in Panel A. Similarly, most of the other categories showed relatively little increase in 2012, and this accords with the lack of hour-to-hour responsiveness in Panels B–F. Finally, it is important to note that, while hydroelectric resources display some hour-to-hour variation in Figure 3, the year-to-year variation is entirely exogenous – it depends on total precipitation.

4.3 Unit-Level Generation Regressions

The generation regressions by category give a valuable overview, but they provide no detail about which particular plants tend to be the most responsive to system-wide demand, nor about the geographic location of production. Therefore, we next estimate generation regressions for each unit that appears in the CEMS data. The estimating equation for these regressions is very similar to equation (1) except the unit of observation is now the individual generating unit j,

$$generation_{jt} = \sum_{b} (\alpha_{bj} \cdot \ \mathbb{1}\{system\text{-}wide\ thermal\ generation_t = b\}) + e_{jt}. \qquad (2)$$

The right-hand side bins, again indexed by b, are now defined over total generation by all the CEMS units in our balanced sample. We use this rather than total system demand because we want to identify the ordering within the category of natural gas units, and because we want to attribute changes from the pre-period to the post-period only to the SONGS outage, not to concurrent changes to renewables, hydro, or demand. Simultaneity is again not a concern: system-wide thermal generation is driven by exogenous shifts in electricity demand, which is both highly inelastic and highly variable across hours, and by idiosyncratic fluctuations in generation from renewables, hydro, and other non-CEMS categories of generation. We further examine this exogeneity assumption in the Online Appendix.

We estimate these unit-level generation regressions using two separate samples corresponding to before and after the SONGS closure. Observing behavior before the closure allows us to construct a counterfactual for what would have occurred if SONGS had not closed. For the pre-period, we again use data from April 20, 2010 to January 31, 2012, the year and a half leading up to the SONGS closure. For the main analysis we exclude generating units that enter or exit during our sample period, focusing only on continuously-operating generating units plus Huntington Beach units 3 and 4, which operated through most of our sample period, but were converted to synchronous condensers in January 2013.[20] We explore entry and exit in the Online Appendix, finding that excluding the units that enter or exit during our sample period is unlikely to bias our results.

Sample graphs of the coefficients from these pre-period unit-level regressions are shown in Figure 4. We show twelve plants: the four largest plants for each of three technologies. As can be seen in Panel A, the combined cycle plants tend to turn on, and even reach capacity, at fairly low levels of system demand. These units are generally new, large, and efficient. The combustion turbines in Panel B are turned on at higher levels of demand and have much smaller capacity. Finally, the boilers (Panel C), which are generally large and old, are turned on only at high levels of system demand.

For the post-period, we use data from February 1, 2012 through January 31, 2013. These are the first twelve months after the SONGS closure. While it would be interesting to examine longer-run changes in the market, this gets difficult to identify because the market is changing over time, both endogenously as costly transmission investments are made in response to the SONGS closure, and exogenously as, for example, new generation sources come online.[21]

When estimating the standard errors, we cluster by sample month to allow for arbitary spatial correlation and serial correlation within sample month. To examine whether this approach sufficiently accounts for serial correlation, we regressed the residuals on their lags. Beyond fifteen days, the estimated coefficients are close to zero and not statistically significant.

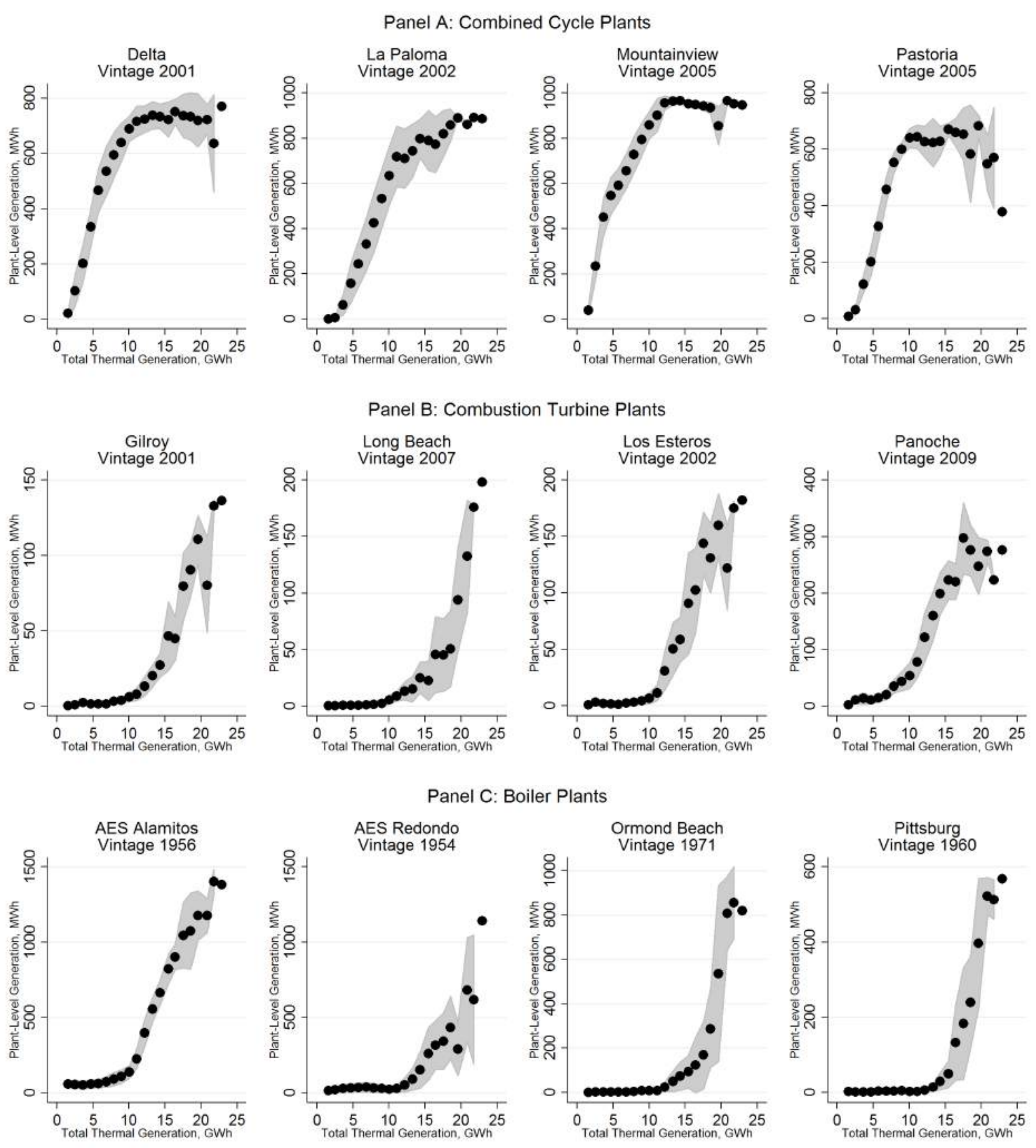
4.4 Predicted and Residual Effects

We thus have a set of coefficients α for each of 21 bins at 184 generating units in 2 time periods, for a total of over 7,000 coefficients. We summarize these estimates using what we call "predicted" and "residual" effects. For each generating unit, we define the predicted change in generation caused by the SONGS closure as follows: maintaining the coefficients from the pre-period, while requiring an additional 2,150 megawatt hours of generation to fill the SONGS gap. This is akin to assuming that the ranking of marginal costs did not change. Recalling that the width of each bin is equal to 1,075 megawatt hours, the predicted change (induced by the SONGS closure) across all bins b and all generating units j in a geographic

[20] We also drop four generating units which are owned by the Los Angeles Department of Water and Power (LADWP). As described earlier, LADWP maintains its own electricity generation and also imports power from other states through long-term contracts, and it is not part of the CAISO market.

[21] In the Online Appendix, we include results estimated with a post-period which goes through June 30, 2013, and the estimated residual effects results are similar but somewhat attenuated. This is exactly what one would expect as investments in new transmission capacity begin to relieve the constraint.

Figure 4: Generation Regressions by Individual Plant



Note: These figures plot the coefficients from 12 separate plant-level generation regressions, for the four largest plants within three technology types as indicated in the panel headings. As described in detail in the text, these regressions are estimated using hourly data from April 20, 2010 until January 31, 2012. The x-axis is total generation from all plants in the CEMS panel and the y-axis is average generation, in MWh, for that individual plant. The grey areas show 95 percent confidence intervals, where standard errors are clustered by sample month.

region (J_{North} or J_{South}) is equivalent to moving up two bins:

$$\sum_{b>2} \sum_{j \in J} \left(\alpha_{bj}^{pre} - \alpha_{b-2,j}^{pre} \right) \cdot \theta_b^{post} \tag{3}$$

where θ_b^{post} is the fraction of hours that system-wide demand was in bin b during the post-period.[22]

Thus we are predicting how generating units will behave after the SONGS closure, modeled as a non-marginal shift in the net demand that each unit faces. Each unit's generation regression is identified using hour-to-hour variation, but the predicted effect of the SONGS closure is a shift in the entire distribution of net demand. The hourly variation is important, because as total demand varies tremendously across time, so does the impact of the closure on the behavior of individual generating units.

The residual effect we measure is the change in generation from the pre-period to the post-period, conditional on a given level of system demand:

$$\sum_{b} \sum_{j \in J} \left(\alpha_{bj}^{post} - \alpha_{bj}^{pre} \right) \cdot \theta_b^{post}. \tag{4}$$

Whereas the predicted effect models how a unit's behavior changes when the net demand that it faces increases, the residual effect measures how the unit's behavior changes conditional on a given level of net demand. Residual effects can be positive or negative, reflecting whether units are operating more or less than would be predicted from pre-period behavior. In the analysis that follows, we discuss potential drivers of these residual effects, as well as their impact on the cost of electricity generation.

Perhaps the most important drivers of residual effects are transmission constraints. Because SONGS was located in a load pocket, its closure led to binding physical constraints on the grid. To examine the broad pattern of transmission congestion, we begin by presenting results by region. Additionally, we evaluate the predicted and residual changes for subsets of hours when transmission constraints are most likely to bind. We consider two such subsets, each totaling approximately five percent of hours. First, we define weekday summer afternoons as 2 p.m. to 5 p.m. in months June through September. Second, we define high demand hours when total CEMS generation was in the 13th quantile (greater than 13,837 MWh); this leaves approximately the same number of observations as in the weekday summer afternoon results. We verify that both definitions are highly correlated with congestion as defined by the price differential between North and South. They are also correlated with one another,

[22]Note that this cannot be calculated for levels of thermal generation without a pre-period counterfactual, i.e. $b = 1$ and $b = 2$. In our sample, these levels of thermal generation do not appear in the post period, so in practice this is not an issue.

with a simple correlation of 0.30.

To attribute these residuals to the SONGS closure, the identifying assumption is that the ordering of units along the marginal cost curve in 2012 would have been the same as in 2010 and 2011, had SONGS not closed. There are many reasons to think this is a reasonable assumption. These are all natural gas plants, so there is no inter-fuel substitution, and the ordering among plants is essentially a monotonic ordering by heat rate.[23] Moreover, while there was a significant decrease in hydroelectric generation in 2012, this would not have affected the ordering of the natural gas units and, if anything, would have made transmission constraints *less* likely to bind. In the Online Appendix, we explore these and several additional potential confounding factors in depth. Our approach is not a panacea. As with any before-and-after comparison, we cannot rule out the possibility that our estimates are affected by other factors that are changing in the market at the same time. We conclude, however, in examining each potential confounding factor carefully, that any bias is likely to be small in magnitude. Moreover, it is hard to envision any alternative explanation for the particular pattern of regional and temporal residual effects that we observe.

5 Main Results

5.1 Impact on the Regional Pattern of Generation

Table 3 describes the effect of the SONGS closure on the geographic pattern of generation in California during the twelve months following the closure. The reported estimates are average hourly changes in MWh. Panel A reports effects for all hours. The predicted change in generation is similar in the North and the South, with both regions predicted to increase generation by about 900 MWh per month. The Central California column represents many fewer plants, and accordingly a smaller predicted change (300 MWh). By design, the total predicted effect is approximately equal to 2,150 MWh, the lost generation from SONGS. This geographic pattern reflects where in the state thermal resources are located. Without any transmission constraints, our estimates imply that about 40 percent of the lost output from SONGS would have been produced by plants located in Southern California.

The residual estimates show the displacement of generation from Northern generating

[23] Our methodology would be less useful in markets where fuel price changes affect the dispatch order between different forms of generation. For example, in many U.S. markets natural gas combined cycle plants have been moving ahead of coal in the dispatch order (Cullen and Mansur, 2014). Our methodology could still be used in these settings, but only for identifying predicted changes within each fuel type. Moreover, our methodology implicitly assumes that generators face very similar fuel prices. As we show in the Online Appendix, this is an excellent assumption in our context, but one could envision situations in which natural gas pipeline constraints and other bottlenecks would lead this to be violated.

Table 3: The Effect of the SONGS Closure on the Regional Pattern of Generation

	Average Hourly Change in Net Generation, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Predicted Change (MWh)	892	300	944
	(18)	(15)	(18)
Residual Change (MWh)	150	20	-140
	(73)	(66)	(79)
	Panel B: Weekday Summer Afternoons		
Predicted Change (MWh)	1068	259	822
	(47)	(17)	(39)
Residual Change (MWh)	237	76	-260
	(144)	(61)	(119)
	Panel C: High Demand Hours		
Predicted Change (MWh)	1207	174	753
	(44)	(30)	(35)
Residual Change (MWh)	431	4	-381
	(144)	(57)	(129)
Observations (Hour by Unit)	2,285,140	267,410	1,920,490
Number of Generating Units	94	11	79
Number of Plants	42	5	43
Total Capacity (MW)	15,922	2,887	11,776

Note: This table reports our estimates of the change in generation that resulted from the SONGS closure on January 31, 2012. We report both "predicted" and "residual" effects. The predicted calculation gives the increase in generation at marginal units, assuming 2,150 MWh of lost generation from SONGS. The residual calculation gives the difference between actual and expected generation, as explained in the text. For all calculations our sample includes hourly observations between April 20, 2010 and January 31, 2013. We exclude generating units that enter or exit during the sample period. As indicated by the column headings, we report estimates for three California regions as defined by the Path-15 and Path-26 transmission interconnections. Panel A reports estimated impacts for all hours. Panel B reports estimates for 2 p.m. to 5 p.m. in months June through September. Panel C reports estimates for hours when total CEMS generation was in the 13th quantile (13,837 MWh) or greater. Standard errors (in parentheses) are clustered by sample month.

units to Southern units. Relative to our predictions, the Southern units increased generation by 150 MWh, while the Northern units decreased generation by 140 MWh. To put this in perspective, the average plant-level capacity is around 380 MW in the South and around 270 MW in the North, so these effects are approximately half the size of a typical plant. The results are starker when the sample is limited to the hours in which transmission constraints are most likely to bind. On weekday summer afternoons (Panel B), the residual effect almost doubles, to a 237 MWh increase in the South and 260 MWh decrease in the North. In the five percent of hours with the highest level of system demand (Panel C), the residual effect is an increase in the South of 431 MWh and a decrease in the North of 381 MWh. Thus, the estimates indicate that during peak periods as much as 75 percent of the lost generation from SONGS was met by plants in Southern California. To get a sense of the magnitude, this residual effect is comparable to an increase in capacity factor of three percentage points in the South and a decrease of three percentage points in the North.

These results implicitly assume that the entire displaced SONGS generation (2,150 MWh) was met by in-state CEMS units. This is a reasonable approximation given the lack of responsiveness in all other categories of generation observed in Figure 3. The one notable exception is imports, which are responsive over some ranges of demand. To account for this, we calculated the predicted impact on imports of a shock to total demand equal to 2,150 MWh, using the generation regression for imports. This exercise implies that around 25 percent of the lost generation from SONGS would have been replaced by imports. One could imagine adjusting the predicted estimates in Panel A of Table 3 accordingly. For weekday summer afternoons and high demand hours, however, we find a very small response in imports, consistent with the visual evidence in Figure 3. On weekday summer afternoons, only 4 percent of the lost generation would have made up by imports, and in high demand hours it would have been less than 1 percent. Further details, discussion, and figures plotting post-period generation regressions by category are presented in the Online Appendix.

The table also reports standard errors. The predicted changes are estimated with a high degree of statistical precision and all nine estimates are strongly statistically significant. The estimated residual changes are much less precise and only marginally statistically significant in Panel A. In the Online Appendix, we report results from a series of placebo tests aimed at determining how unusual it is to observe this magnitude and pattern of residual effects. In particular, we repeat the analysis six times using the exact same specification, but with different years. In the first placebo test, for example, we estimate the model as if SONGS had closed in January 2007 rather than January 2012. Overall, the estimated residual effects in these other years do not follow the pattern observed in 2012. Some of the estimates are similar in size to our main results. However, when one looks closely at non-zero residual effects in other years, they tend to be driven by long outages. To demonstrate this, we show several additional diagnostics on the estimated residuals. In the placebos with the largest estimated residual effects, the standard deviation, skewness, and kurtosis are all larger (in absolute terms) than in 2012, indicating extended outages and other large year-to-year changes in generation at a few individual plants rather than correlated changes in generation across many plants.

5.2 Impact on Generation Costs

We next quantify the change in the total cost of production associated with these generation impacts. To do so, we must first calculate the marginal cost for each generating unit. As is common in the literature, we calculate marginal cost using information on heat rates, fuel prices, and variable operations and maintenance costs (VOM): $MC_j = heat\ rate_j \cdot fuel\ price_j + VOM_j$.[24] For the unit-level heat rate, we divide the total heat input over our time frame (in MMBtus) by total net generation (in MWhs). This abstracts from ramping rates, as is common in the literature.[25] We obtain daily natural gas prices from Platts Gas Daily and calculate the average post-period price. We focus, in particular, on the PG&E City Gate price for the North, and the SCG City Gate price for the South. For VOM, we assume $3.02 per MWh for combined cycle plants and $4.17 per MWh for all other plants (in 2009$), following CEC (2010). The resulting marginal cost estimates range from $24 per MWh for generating units with favorable heat rates to $81 per MWh for units with high heat rates.

In Figure 5, we plot the marginal cost curve for electricity in California for 2012. We use our estimates of marginal cost for all thermal units. For the capacity of these units, we use the maximum observed hourly generation in our sample. For hydroelectric, renewables, and nuclear, we proxy for capacity using the average hourly generation in the post-period (February 2012 through January 2013), from CAISO. While these types of generation have higher rated capacities, the average generation in the post-period is more relevant given constraints set by weather conditions. We assume zero marginal cost for hydro and renewables production. For the marginal cost of nuclear units, we use a nuclear fuel cost estimate of $7.08 per MWh (in 2012$) from Table 8.4 of the EIA's *Electric Power Annual* (EIA 2012), plus a nuclear VOM estimate for California of $5.27 per MWh (in 2009$) from CEC (2010).[26]

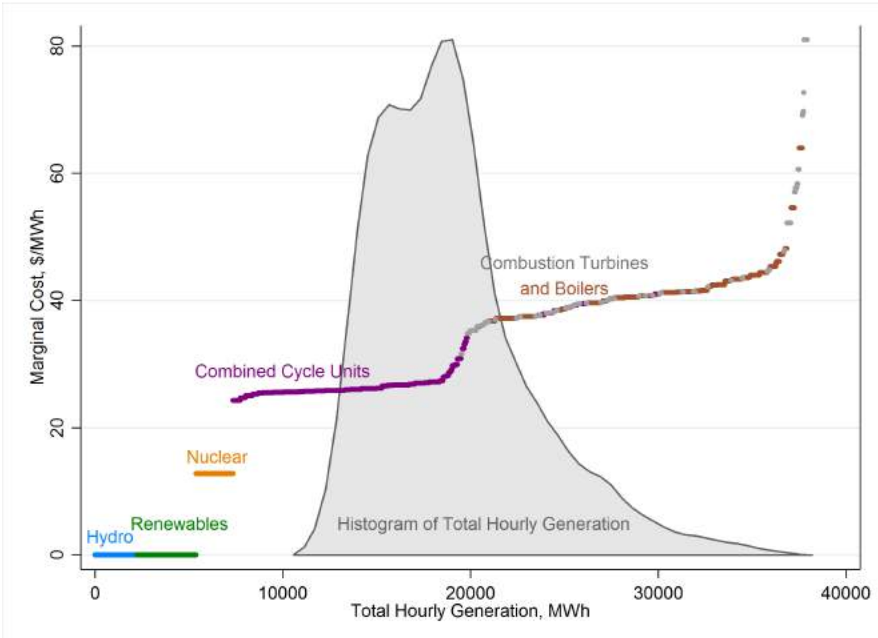
We overlay on the marginal cost curve a histogram of total hourly generation in the post-period. In most hours, the marginal generating unit is a combined cycle natural gas unit, with

[24] As discussed in Section 2.1, separating fixed and variable operations and maintenance costs is challenging. Given the small magnitude of O&M at fossil-fuel plants, this distinction is not qualitatively important for our cost estimates. Below we discuss how we treat fixed O&M costs at SONGS and at California's natural-gas fired power plants.

[25] While abstracting from ramping rates and other dynamic considerations is common in the literature, Reguant (2014) finds that start-up costs play an important role in bidding behavior and production patterns. Our preferred specification uses constant heat rates, thus averaging across differential fuel use during start-up and ramping, so as not to bias our results with changes over time in heat rates driven by confounding factors. To verify that our results are not sensitive to this specification, we considered several alternatives that allowed heat rates to vary over time. With these alternative specifications all our results are qualitatively similar, and the estimate of the total cost impact of the SONGS closure is about five percent smaller.

[26] Biomass/biogas are not shown, as marginal cost numbers are not available. The marginal cost of biomass generation is likely in the range of the combined cycle units with an average production over this period of around 500 MWh.

Figure 5: The Marginal Cost of Electricity in California, 2012



Note: This figure was constructed by the authors using their measures of marginal cost and capacity for electricity generating resources in the state of California in 2012. Imports are not included. See the text for details.

marginal cost (given the average post-period natural gas price) of around \$27 per MWh. In high demand hours, however, the marginal unit is typically either a combustion turbine or a boiler (again, fueled by natural gas), with marginal cost around \$40 per MWh.

To quantify the cost impact of the SONGS closure we run regressions similar to the unit-level generation regressions, except the dependent variable is now the cost of generation rather than the quantity:

$$(MC_j \cdot generation_{jt}) = \sum_b (\delta_{bj} \cdot \mathbb{1}\{system\text{-}wide\ thermal\ generation_t = b\}) + \mu_{jt}. \tag{5}$$

The advantage of using this regression is that we can again decompose the total change in cost into predicted and residual changes. Results are given in Table 4. Taking a weighted average across all hours, the predicted increase in the total hourly cost of thermal generation was \$29,000 in the South, \$8,000 in the Central region, and \$27,000 in the North – totaling \$63,000 statewide. The average cost implied is approximately \$29 per MWh. These estimates again assume that none of the lost generation from SONGS was replaced by imports. This is likely a good approximation because the California marginal cost curve is quite elastic in most hours, so the marginal cost of out-of-state generation necessarily must have been close

Table 4: The Effect of the SONGS Closure on Thermal Generation Costs

	Average Hourly Change in Total Generation Cost, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Predicted Change ($000's)	28.6	7.9	26.5
	(0.6)	(0.4)	(0.5)
Residual Change ($000's)	7.1	0.5	-3.0
	(2.9)	(1.7)	(2.5)
	Panel B: Weekday Summer Afternoons		
Predicted Change ($000's)	41.6	7.5	27.4
	(1.6)	(0.5)	(1.4)
Residual Change ($000's)	8.8	1.4	-9.1
	(5.1)	(1.6)	(4.2)
	Panel C: High Demand Hours		
Predicted Change ($000's)	49.7	5.7	27.8
	(1.9)	(0.8)	(1.4)
Residual Change ($000's)	16.3	-0.5	-14.5
	(4.8)	(1.7)	(4.8)
Observations (Hour by Unit)	2,285,140	267,410	1,920,490
Number of Generating Units	94	11	79
Number of Plants	42	5	43
Total Capacity (MW)	15,922	2,887	11,776

Note: This table reports estimates of the cost of meeting the lost generation from SONGS during the first twelve months following the closure. The format of the table and underlying data are identical to Table 3, but we have used our measures of marginal cost for each generating unit to calculate the change in total generation cost. As we explain in the text, this includes changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. Standard errors (in parentheses) are clustered by sample month.

to the marginal cost of the in-state generation. As such, we expect our estimate of $63,000 to be close to the true change accounting for imports.

The residual changes are also significant, and their spatial pattern follows what would be expected from transmission constraints. While total hourly generation costs increased by $7,100 in the South and $500 in the Central region, it decreased by $3,000 at Northern generating units because of the decrease in quantity. System-wide, this implies an average hourly increase of $4,500 coming from the residual changes in generation. While lower-cost units were available in the North, they could not be used because of the transmission constraints. This residual effect reflects not only North-South transmission constraints, but also local transmission constraints in and around San Diego and Los Angeles, as well as other physical limitations of the grid. Part of the challenge with SONGS closing was that there was now very little generation in northern San Diego county that could be used to boost the voltage of electricity transmitted from far away.[27] Maintaining some "reactive" power locally was another reason why higher-cost Southern units would have operated more than predicted in 2012.

The total cost increase at thermal power plants statewide, averaged across all hours and including both predicted and residual effects, is almost $68,000 per hour. This amounts to a 13 percent increase in total in-state generation costs.[28] As another point of comparison, the average post-period price in the California wholesale electricity market (quantity-weighted) was $32 per MWh. Multiplying this by total quantity (i.e. 2,150 MWh) gives $68,000 per hour. The two measures are quite close together because the supply curve is fairly elastic in most hours throughout the year. Thus the cost of the marginal generating unit is not very different from the cost of inframarginal units.

Panels B and C of Table 4 report estimates of the generation cost impacts for weekday summer afternoons and high demand hours, when transmission constraints are more likely to bind. The predicted effects are larger than in Panel A, because the marginal generating units at these hours are higher up on the marginal cost curve. The change is particularly high in the South, where the generation impacts were larger. The residual changes in total cost are also higher than in Panel A, reflecting a combination of larger residual changes in generation and higher marginal costs. As we discussed earlier, imports do not substantially increase during peak periods, so we expect these estimates to be close to the true total change in cost. The system-wide total hourly change in thermal costs is $78,000 on weekday summer afternoons, and $84,000 in high demand hours. For comparison, the average weekday summer afternoon wholesale price (quantity-weighted) was $49 per MWh. Multiplying this by SONGS capacity gives $106,000 per hour. The same calculation for high demand hours (Panel C) also gives $106,000 per hour. These measures are considerably higher than our estimate because supply is relatively inelastic during these hours so the marginal generating unit has a much higher cost than the inframarginal units.

[27] Electricity gradually drops in voltage when it is transmitted long distances, so some local generation is necessary to complement electricity produced far away. Much of the attention since the SONGS closure has been on adding local generation, and in particular, on adding generation that provides "reactive" power for voltage regulation. In 2013, two generators at the Huntington Beach Plant were converted to synchronous condensers to provide local voltage support CAISO (2013a). Since 2013, CAISO has also been taking steps to expand local transmission capacity in and around San Diego County (CAISO 2013e; CAISO 2014).

[28] To calculate this, we assume that the average hourly cost for other thermal generation (i.e., not observed in the CEMS data) is equal to the average cost we observe in our sample.

5.3 Impact on Emissions

In addition to the private cost of generation we calculate above, we quantify the impact of the generation changes on carbon dioxide emissions. Using the CEMS data, we first calculate carbon emissions rates for all generating units in our sample. We then use the same type of regression as we used for the generation and cost changes, but now with carbon dioxide emissions, in metric tons, as the dependent variable:

$$(carbon\_rate_j \cdot generation_{jt}) = \sum_b (\lambda_{bj} \cdot \mathbb{1}\{net\ system\text{-}wide\ demand_t = b\}) + \nu_{jt}. \qquad (6)$$

Summing across all plants and all hours, we estimate an average increase of 1,030 tons per hour during the 12 months following the SONGS closure. For comparison, the average hourly total emissions at CEMS plants was 3,730 tons between 2009 and 2011, so this is more than a 25 percent increase in total emissions. As with the previous calculations, this assumes that none of the lost generation from SONGS was replaced by imports. If the emissions rates of marginal out-of-state generators are comparable to the emissions rates of the CEMS plants we observe, then our carbon calculations will still be correct. If, however, there are *marginal* generators out-of-state that are fueled by coal, then our carbon estimates will be a lower bound. These calculations also assume that none of the emissions were offset via California's cap and trade program for carbon dioxide. While California power plants are currently covered by a carbon cap and trade program, they were not yet covered in 2012. As a result, the 2012 increase in carbon dioxide emissions caused by the SONGS closure would not have been offset.[29]

We also examine the impact on sulfur dioxide and nitrogen oxides emissions. Our estimates imply that the SONGS closure increased emissions of both pollutants. However, natural gas plants emit small enough amounts of these criteria pollutants that the implied economic cost of the change in emissions is small compared to the carbon dioxide impacts. See Muller and Mendelsohn (2012) for recent estimates of marginal damages. Moreover, a portion of NOx emissions are capped in the RECLAIM market around the Los Angeles area, so some of these increases may have been offset by decreases in other sectors.

[29] Our annualized cost estimate does include January 2013 emissions, which totalled 0.7 million tons. These were covered by the new cap and trade program, but at a permit price of under $15 (source: calcarbondash.org, based on ICE contracts), compared to the IWG's social cost of carbon of $35 per ton that we use later in the analysis. Accordingly, only 3 percent of the twelve-month carbon costs that we report would have been internalized.

5.4 Total Impact of SONGS Closure

Table 5 summarizes the total impact of the SONGS closure. In Section 5.2 we calculated that the SONGS closure increased thermal generation costs by almost $68,000 per hour during the first 12 months following the closure. As we described earlier, California nuclear plants have a marginal cost of about $12.8 per MWh, so each hour that SONGS was not operating also represents a savings of about $28,000 per hour. Thus the total net increase in generation costs from the SONGS closure is $351 million during the first twelve months. This includes a predicted net increase of $311 million and a residual net increase of $40 million. Finally, using a social cost of carbon of $35 per ton,[30] our estimates imply an increase in external costs of $316 million during the first 12 months.

The table also reports standard errors. As with our previous results, the predicted effects (i.e. generation costs and carbon dioxide emissions) are much more precisely estimated than the residual effect. This reflects how both effects are identified. With the predicted effects, identification comes from hour-to-hour comparisons between periods with different levels of net system demand. There is rich variation in net system demand driven by weather and other factors, so the underlying coefficient estimates are precisely estimated. The residual effects use these same underlying coefficient estimates but, in addition, identification relies on comparing coefficient estimates before and after the SONGS closure. The placebo tests that we described in Section 5.1 show that it is not unusual to observe large year-to-year residual effects. All six placebo estimates of the residual net increase in generation costs are smaller than $40 million, but in some years the estimate is close in magnitude. Overall, the placebo results suggests that while the pattern of residual effects in 2012 is indeed atypical, the $40 million estimate should be interpreted cautiously.

These estimates are valuable more broadly for thinking about the private and social consequences of nuclear plant closures. In addition to generation cost impacts, the other relevant private cost is the fixed O&M required to keep a nuclear plant open. For SONGS, these costs were about $340 million per year, approximately the same magnitude as the generation cost impacts.[31] Discussions about nuclear plant closures also typically center around the external costs associated with operating a nuclear power plant including storage of spent fuel and accident risk. Quantifying these risks is very difficult because they involve small probabilities of large damages.

[30]The central value of the social cost of carbon used by the U.S. federal government for regulatory impact analysis is $32 per ton (in 2007$) (IWG 2013), equivalent to $35 per ton in 2013 dollars.

[31]The Cost of Generation Model from CEC (2010) reports an annual fixed O&M cost for California nuclear plants of 147.7 $/kW-yr, in 2010 dollars. We multiplied this by the SONGS capacity of 2,150 MW and we translated into current dollars. This number closely matches regulatory documents, in which SCE had forecast fixed O&M costs of $346 million per year prior to the closure (CPUC 2012).

Table 5: The Total Impact of the SONGS Closure

	Total Impact during the Twelve Months following the Closure (Millions of Dollars)
Predicted Net Increase in Generation Costs	311 (3.1)
Residual Net Increase in Generation Costs	40 (10.7)
Value of Increased Carbon Dioxide Emissions	316 (5.8)

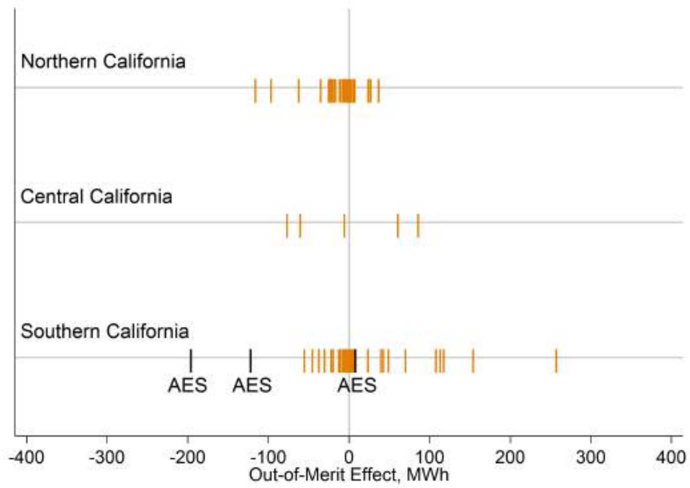
Note: This table reports our estimates of the total economic and environmental impact of the SONGS closure. The predicted net increase subtracts generation costs at SONGS from the predicted increase in thermal generation costs. The residual net increase is the additional increase in generation costs due to transmission constraints and other physical limitations of the grid. As we explain in the text, these generation cost impacts include changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. Carbon dioxide emissions are valued at $35/ton, as described in the text. All dollar amounts in year 2013 dollars. Standard errors (in parentheses) are clustered by sample month.

These results also highlight the evolving economics of U.S. nuclear power we discussed in Section 2.1. The generation cost impacts would have been much higher if natural gas prices had not fallen so much in recent years. At the level of natural gas prices seen in 2007, for instance, the generation cost impacts from the SONGS closure would have been twice as high. This is in line with our discussion about how the shale gas boom has severely worsened the economics of existing nuclear plants. Historically nuclear plants earned substantial operating profits (Davis and Wolfram, 2012), but more recently these profits have been eroded by falling wholesale electricity prices (EIA 2014). Along a similar vein, the convexity of the supply curve implies that the generation cost impacts also could have been much higher had the system been further stressed by an extended period of hotter-than-average weather or an outage at another major power plant.

6 Plant-Level Impacts

Our empirical approach generates estimates of predicted and residual effects not only at a regional level, but also for individual plants. Averaging across all hours, the largest predicted increases in generation were at large combined-cycle plants with low marginal cost. As Figure 5 shows, in most hours the equilibrium is at a fairly elastic portion of the supply curve, with costs around $27 per MWh. The largest positive residual increases tend to be at generating units located in the South and the largest decreases at generating units in the North, as expected. Full results are provided in the Online Appendix.

Figure 6: Plant-Level Residual Changes in High Demand Hours



Note: This figure plots plant-level hourly average residual changes by region. High demand hours are defined as hours when total CEMS generation was in the 13th quantile (13,837 MWh) or greater. Estimates for AES-owned plants are indicated with black lines, while all other estimates are orange. Details on the calculations are given in the text.

The differences between the South and North are starker during hours when transmission constraints were most likely to bind. Not surprisingly, the predicted increases are largest at plants with much higher marginal cost: around $40 per MWh. The largest residual increases are at Southern plants. Also, as expected, several of the largest residual decreases are at plants in the North. There are two important exceptions, however. The two largest residual decreases in high demand hours were at plants in the South: Alamitos and Redondo, both owned by AES. These two large plants were on the margin in high demand hours: they had large predicted changes. Moreover, given their location in the South, they would have been expected to have residual *increases*. To illustrate the anomaly these plants represent, we show in Figure 6 estimated residual effects by plant for high demand hours, separated by region. The AES plants are shown with black lines, while all other plants are shown with orange lines. While the other Southern California plants generally exhibit positive residual effects, the estimated residual effects for two of the three AES plants are clearly large and negative.

As it turns out, the AES plants have been investigated for market violations. They were operated through a tolling agreement with JP Morgan Ventures Energy Corporation, a subsidiary of JPMorgan Chase. Following investigations by the California and Midcontinent System Operators (CAISO and MISO), the Federal Energy Regulatory Commission has alleged market manipulation by JP Morgan at these and other plants.[32] FERC, CAISO, and

[32]To understand FERC's charges against JP Morgan it is helpful to have a bit of broader legal context. Regulatory oversight of electricity is different than for many goods, in that it is illegal to exercise unilateral

MISO asserted that JP Morgan engaged in twelve different manipulative bidding strategies between September 2010 and November 2012 in both the California and Midcontinent markets. Some of the strategies, particularly in 2011, were designed to lead the independent system operator to schedule the generating units even when it was uneconomical to do so, then to pay prices above the wholesale price through so-called make-whole payments. Other strategies, particularly in 2012, involved submitting extremely high bids but relying on the ISO's dynamic scheduling constraints to lead the bids to be accepted. For details on the individual strategies, see FERC (2013). In 2013, JP Morgan agreed to pay a civil penalty of $285 million and to disgorge $125 million in alleged unjust profits.

Given the level of market power exercised during the California electricity crisis (see, e.g. Borenstein, Bushnell and Wolak, 2002), it may be a bit surprising that we do not see evidence of widespread market manipulation. However, CAISO has been actively engaging in bid mitigation since 2012: replacing submitted bids with default cost-based bids (CAISO 2013b). In principle, this could have had two effects: directly mitigating any attempts to exercise market power, and also discouraging firms from even attempting.

It would be interesting to use our results to calculate the profit earned by AES by their alleged behavior, potentially then comparing this number to the settlement with FERC. Several things prevent us from being able to do that. First, since FERC alleged market manipulation in both the pre- and post-periods, we do not know whether the residual decreases at Alamitos and Redondo are a result of unusually high generation in 2011 or withholding in 2012. Second, the settlement with JP Morgan is still relatively recent, so it is hard to compare behavior before and after the settlement. As more data become available from post-settlement, it might be possible to do more analysis. Finally, much of the manipulation alleged by FERC was aimed at earning revenues through exceptional dispatch and other out-of-market operations, and we do not observe these payments.

We do, however, re-examine our main results in light of the FERC investigation. In the Online Appendix we again present estimates of the regional impact (as in Table 3), but this time separating three plants owned by AES from the other Southern plants. The residual increases in the Southern units are even larger than in Table 3, once the plants with alleged market manipulation are separated out. We believe this validates our overall approach in two important ways. First, it provides more evidence that our residual estimates do indeed reflect the effects of transmission constraints between the Northern and Southern markets. Second, it suggests that our residual estimates can serve as a valuable diagnostic tool, pointing to generating units where one might suspect non-competitive behavior.

market power. FERC is charged with a statutory mandate dating back to 1935 which requires wholesale electricity prices to be "just and reasonable," allowing for the recovery of production costs and a "fair" rate of return. See Wolak (2005) for additional discussion.

7 Conclusion

Motivated by dramatic changes in the profitability of existing nuclear power plants in the U.S., we examine the exit decision of a large nuclear plant in California. We find that the SONGS closure increased the private cost of electricity generation in California by about $350 million during the first twelve months. For comparison, the annual fixed costs of keeping the plant open were around $340 million, corroborating anecdotal reports about nuclear power plant profitability. Of the $350 million, $40 million reflects costs not predicted by the pre-period supply curve. This reflects transmission constraints and other physical limitations of the grid that necessitated that a high fraction of lost generation be met by plants located in the Southern part of the state. These constraints also increased the scope for market power, and we find evidence consistent with one company acting non-competitively.

We also find that the closure had a large environmental impact. Because virtually all of the lost production from SONGS was replaced by natural gas generation, the closure increased carbon dioxide emissions by 9 million metric tons during the first twelve months. At $35 per ton, the economic cost of these emissions is almost $320 million. A large fraction of nuclear plants worldwide are beginning to reach retirement age, and it is important to take these external costs into account as decisions are made about whether or not to extend the operating lives of these plants. Current policies aimed at reducing carbon emissions tend to focus on wind, solar, and other renewables, but keeping existing nuclear plants open longer could mean hundreds of millions of tons of carbon abatement.

Our results also illustrate the challenges of designing deregulated electricity markets. Wolak (2014*b*) argues that while competition may improve efficiency relative to regulated monopoly, it also introduces cost in the form of greater complexity and need for monitoring. Transmission constraints add an additional layer to this complexity by implicitly shrinking the size of the market. Constraints increase the scope for non-competitive behavior, but only for certain plants during certain high-demand periods. Understanding and mitigating market power in these contexts is difficult and requires an unusually sophisticated regulator.

Despite these challenges, the experience in California in 2012 also provides some cause for optimism. An enormous generating facility closed suddenly and unexpectedly during a year with low hydroelectric generation, yet there was essentially no disruption in supply and wholesale prices remained steady. In part, these 'steady' prices were only an illusion, driven by a lucky coincidence in the form of decreased natural gas prices. However the experience also points to a more mature, more flexible market that, although imperfect, provides many of the right incentives for generation and investment.

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Appendix

A1.1 Discussion of Potential Confounders

In this Online Appendix we evaluate the potential for confounding factors to influence our results. We are interested, in particular, in potential bias of our main estimates of predicted and residual changes. The following sections consider natural gas prices, other sources of in-state generation, entry and exit of generating units, imports, and demand. Although it is important to go through these potential confounding factors carefully, we end up concluding that overall our estimates are unlikely to be affected by changes in these other market conditions.

Before discussing the specific concerns, it is useful to clarify exactly what we mean by bias. Consider, for example, our estimates of predicted effects. Conceptually, what we hope to capture with our predicted estimates is the change in generation from the SONGS closure that would have occurred if there were no transmission constraints or other physical limitations of the grid. Implicitly, we want to hold everything else constant in this calculation so that the estimates reflect the true causal impact of the closure. Our empirical strategy is to build this counterfactual by constructing the unit-level generation curves using data from before the closure, and then to move up these curves by the amount of lost generation. An illustration is provided in Figure A1.

Thus, in some sense, no change to the market in 2012 could "bias" these results. Our predicted estimates are constructed using pre-closure data only, so they provide predicted changes in generation given the market conditions prior to 2012. An alternative approach for estimation would have been to use post-closure data to construct generation curves, and then to move down these curves by the amount of generation SONGS would have produced had it stayed open. Both approaches build a counterfactual for the SONGS closure, but we prefer our approach because it facilitates a straightforward decomposition of the impact into predicted and residual effects (see Figure A1). Since there is no information from 2012 in these estimates, it does not make sense to think about them being biased by anything that happened in 2012. Nonetheless, using pre-closure data to construct our counterfactual raises important questions about changes in market conditions. Put simply, are the market conditions in 2012 so different that our predictions based on pre-closure data are likely to be misleading? The primary objective of the following sections is to work through the different potential confounders. Even though market conditions are constantly changing, we end up concluding that overall our predicted estimates are unlikely to be meaningfully biased during the twelve months following the closure. As more time passes, conditions become considerably different from the pre-closure period; for this reason we focus on predicted estimates for the twelve months following the closure.

Conceptually, we want our residual estimates to reflect the difference between actual generation and the generation that would have occurred if there were no transmission constraints or other physical limitations of the grid. These estimates rely on the same counterfactual constructed for the predicted estimates, so all the same questions arise about potential confounders. There is also an additional potential concern for our residual estimates. The pattern of price differentials make it clear that transmission constraints and other physical limitations of the grid were more likely to bind post-closure. In the paper we attribute this change to the SONGS closure. The pattern of observed prices, both over time, and across California regions tends to support this interpretation. Nonetheless, it is important to consider the possibility there was some other simultaneous change in market conditions that influenced these constraints. We investigate several alternative explanations in the following sections and conclude that none of these alternatives can explain the particular pattern of geographic and temporal residuals that we see in the data.

A1.2 Changes in Natural Gas Prices

Figure A2 shows that there were large changes in natural gas prices during our sample period. Overall, natural gas prices were around 30 percent lower in 2012 than they were in 2011. These lower prices reduced the cost of replacing the lost generation from SONGS, relative to what one would have calculated based on 2011 prices. We emphasize this point in describing our results and use 2012 prices when quantifying the cost of increased thermal generation.

In addition, it is natural to ask whether these price changes could somehow bias our estimates of predicted and residual changes. In this section we evaluate several potential concerns and, at the same time, discuss closely related potential concerns about changes in the price of permits for Southern California's cap-and-trade program for nitrogen oxides (NOx). Permit prices affect the marginal cost of thermal generation and thus raise very similar questions to changes in natural gas prices, so it makes sense to address both at the same time. Overall, the evidence suggests that our results are unlikely to be meaningfully affected by these price changes.

The main potential concern is changes in the ordering of plants. Our unit-level regressions reflect the ordering of plants along the marginal cost curve. Plants with low heat rates are more efficient, producing large amounts of electricity per unit of fuel input, so these plants operate all the time. Plants with higher heat rates are less efficient, so they appear at the high end of the marginal cost curve and operate less frequently. If the changes in natural gas prices affected this ordering, this could bias our estimates of predicted and residual effects. We could make mistakes, for example, in predicting which plants would meet the lost generation from SONGS.

Although this is a reasonable concern, there are several reasons why we would not expect much change in the ordering of plants. First, there is very little coal or other fossil fuels in the California electricity market, and thus little scope for inter-fuel changes in the ordering of plants. Nationwide the decrease in natural gas prices has led to widespread substitution of natural gas for coal (Cullen and Mansur, 2014), but essentially all of this has occurred outside the state of California. Second, a large fraction of California generation operates at close to zero marginal cost. This includes nuclear, 'run-of-the-river' hydro, geothermal, wind, and solar. These resources are ahead of natural gas in the queue, regardless of whether natural gas costs \$2 or \$7 per MMBtu. Third, the ordering of natural gas plants is largely unaffected by natural gas prices. The part of the marginal cost curve made up of by natural gas plants should be thought of, essentially, as an ordering of plants by heat rate. A decrease in natural gas prices reduces the marginal cost of generation for all plants, but the *ordering* is largely unaffected.[33]

Marginal cost also depends on NOx emissions where generators are subject to regional cap-and-trade programs for NOx. Under the RECLAIM program, certain generators in and around Los Angeles must remit permits corresponding to their NOx emissions. As it turns out, however, NOx permit prices were low enough during our sample period that they are unlikely to affect the ordering of plants.[34] In our data, the mean emissions rates for the Los Angeles area plants is 0.4 pounds per MWh (median 0.2 pounds per MWh). The average prices for NOx permits was \$2493/ton in 2010, \$1612/ton in 2011, and \$1180/ton in 2012 (all in 2013 dollars), implying that NOx credit payments make up only a small portion of the plants' marginal costs.[35] Thus NOx permit obligations are unlikely to have meaningfully altered the ranking of plants by heat rate.

A more subtle concern would be differential changes in natural gas prices between the North and South. However, as can be seen in Figure A2, natural gas prices are quite similar in the North and South during the entire period. This makes sense given the network of existing pipelines as well as available storage, which can smooth out short-run capacity constraints in transmission. Although not visible in the figure, prices in the North decreased from the pre- to post-period approximately 2 percent more than in the South. This is a relatively small

[33]Our methodology could still be applied in a setting with multiple fuel types (such as coal and natural gas) or with pipeline congestion leading to regional differences in natural gas prices. Predicted changes could be identified *within* each fuel type or each region, since that ordering would not be confounded by relative movements in fuel prices. The method would, however, be unable to distinguish cross-region or cross-fuel changes in the supply curve arising from transmission congestion as opposed to relative fuel price changes.

[34]We obtain annual average NOx prices from the Regional Clean Air Incentives Market ("RECLAIM") annual reports for 2006-present. Higher frequency prices are not publicly available. We use the prices of credits traded in the same year as the compliance year.

[35]The mean marginal cost would therefore be less than \$0.60 in all three years, compared to wholesale electricity prices that are typically above \$30. A small number of units have substantially higher NOx rates; the highest rate we observe is 5 pounds per MWh.

change, so we would not expect it to have much impact on the ordering of plants.

A1.3 Changes in Other Sources of Generation

Between 2011 and 2012 there were also significant changes in other sources of in-state electricity generation. Most importantly, 2012 was an unusually bad year for hydroelectric generation. The snowpack in 2012 was only half of the historical average level, and total hydroelectric generation in 2012 was less than 2/3rds generation in the previous year.[36] At the same time, almost 700 megawatts of wind and solar capacity were added in 2012 (CAISO 2013b), resulting in large percentage increases in generation from wind and solar. Geothermal and other renewables experienced essentially no change between 2011 and 2012. Finally, non-CEMS thermal units increased generation by five percent between 2011 and 2012.

This section discusses how these changes in other sources of generation could potentially impact our estimates or affect how the results are interpreted. As with the changes in natural gas prices, it is worth emphasizing that these changes are exogenous and should not be viewed as being *caused* by the SONGS closure. Year-to-year variation in hydroelectric generation is driven by idiosyncratic variation in precipitation. And, while new renewables capacity investments do respond to market conditions, it takes at least several years for planning and permitting a new site. The new wind and solar facilities that came online in 2012 were first envisioned in the early 2000s, long before there was any indication of potential safety concerns with SONGS.

It is also important to remember that we measure predicted effects using *net* system demand. When calculating demand for our unit-level regressions, we start with system-wide demand but then subtract from it all electricity generated by these other sources of generation. The generation that is left is what was met by CEMS units. Figure A3 shows a histogram of hourly total CEMS generation for each of these two periods, using the same bin width definition as in the regressions. Panel A shows one year of the pre-period and Panel B shows one year of the post-period. Total generation from CEMS units increases substantially in the post-period to fill in for SONGS and to make up for the decrease in hydro generation.

Changes to these other sources of generation are exogenous, so it does not make sense to think of these resources as making up for the lost generation from SONGS. Wind, solar, and non-dispatchable hydro have a marginal cost of operation near zero, so they operate regardless of what else is happening in the market. California's one other nuclear power plant, Diablo Canyon, also has very low marginal cost and operates around the clock. Moreover, the non-

[36]For historic snowpack levels see the Snow Water Equivalents data from the Department of Water Resources at http://cdec.water.ca.gov/cdecapp/snowapp/sweq.action. On April 1, 2012, the snowpack was at 54 percent of the historical April 1 average.

CEMS thermal units tend to be industrial, commercial, and cogeneration facilities for which electricity generation is a joint decision with other processes, limiting their ability and incentive to respond to market conditions.

Dispatchable hydroelectric generation is somewhat harder to think about, but it is also unlikely to be making up for the lost generation from SONGS. Year-to-variation in precipitation determines total hydroelectric generation, but operators have some flexibility as to *when* these resources are utilized. Short-run generation decisions are determined by a complex dynamic optimization problem. Operators respond to current and expected market conditions, trading off between current prices and the shadow value of the remaining water in the reservoir, subject to minimum and maximum flow constraints. None of this is particularly problematic for our analysis because operators are optimizing the same problem both before and after the SONGS closure. Moreover, the generation curve for large hydro in Figure 3 indicates only a modest amount of intertemporal substitution toward high demand periods.

A related question is how changes in these other sources of generation could have changed the likelihood that the transmission constraints were binding, thus indirectly impacting the ordering of thermal resources. This is potentially problematic because we would like to attribute the observed residual effects to the SONGS outage. Of the other changes in generation, by far the most significant is the decrease in hydro generation. Although this is an important consideration, the decrease in hydroelectric generation in 2012 would have, if anything, made transmission constraints *less* likely to bind. Hydroelectric plants are located primarily in the North,[37] and according to EIA data, 75 to 80 percent of the fall in hydro generation in 2012 occurred in the North. As such, the decrease in hydroelectric generation would have, if anything, actually reduced the need for North to South transmission. Moreover, the changes in wind and solar generation, while large percentage increases, represent small changes when compared to the entire market, and thus are unlikely to have meaningfully contributed to the binding transmission constraints and other physical limitations of the grid. Wind and solar generation statewide increased by 0.17 million and 0.04 million MWh per month, respectively, in 2012.[38] Total monthly generation in California in 2012 was almost 17 million MWh, so these increases combined represent only about 1 percent of total generation.

[37] According to CAISO (2013d), approximately 80 percent of summer capacity is in the North.

[38] According to EIA data, most of this increase in wind and solar generation was in the North. However, the magnitude is much smaller than the decrease in hydro generation. Consequently, the net change in the North for other sources of generation (i.e., hydro plus renewables) was still negative and two to three times the decrease in generation in the South. These exogenous changes would have, if anything, reduced the need for North to South generation.

A1.4 Entry and Exit of Thermal Units

During our sample period, a number of thermal generating units opened or closed, and in this section we discuss the impact of this entry and exit on the interpretation of our estimates. The results in the paper focus on a balanced panel of units, restricting the sample to those units that were continually in service during our sample period of April 20, 2010 through January 31, 2013. As we mention in the paper, we also include Huntington Beach units 3 and 4, which operated for most of this period, but were converted to synchronous condensers in January 2013. Excluding units that enter and exit simplifies the analysis and interpretation but also raises two potential concerns. First, our results could be biased if the entry and exit were endogenous to the closure of SONGS. In particular, it would be a causal effect of SONGS that we are failing to capture. Second, for entry and exit that is either endogenous or exogenous, a separate concern is that these changes could somehow have affected transmission congestion and thus biased our residual effects.

Entry and exit in 2010 and 2011 is clearly exogenous, since the closure of SONGS was unanticipated. We exclude five units that exited in 2010; these units had accounted for 1 to 2 percent of California CEMS generation before their closure. We additionally exclude units that enter in 2010 or 2011, before the SONGS closure was anticipated; these units accounted for 3.5 percent of California CEMS generation in 2012 and 1.8 percent of total California generation. We simply do not have enough pre-period data from these plants to include them in the analysis. Fortunately, this is a small enough part of the market that excluding these plants is unlikely to meaningfully bias our estimates.

Endogenous entry and exit in 2012 are almost certainly not a concern given the short time horizon. New units take years to plan and permit, and the closure of SONGS was unexpected. To verify this, we examined siting documents from the California Energy Commission for the units that opened in 2012. Altogether, these units accounted for less than 1 percent of total California generation. Where we were able to locate the siting documents, we found that applications had been filed in 2008 or 2009, long before the SONGS closure. It is possible that these openings may have been accelerated by the SONGS closure, but we are unaware of any specific cases. In short, we do not think it makes sense to think of this entry as a causal response to the SONGS closure.[39]

More plausibly, the SONGS outage could have delayed plant exit. To the best of our knowledge, the only such case is the extension of operations at Huntington Beach's units 3 and 4. These two units were expected to retire about the same time that SONGS closed,

[39]A related possibility is that existing units made capital investments to change their heat rate or capacity. If caused by the SONGS closure, this would be one of the mechanisms through which our effects operate. If not caused by SONGS, it would confound our results only if it affected transmission congestion.

but remained open in 2012 to provide additional generation and voltage support in Southern California (CAISO 2013b). These units are in our sample, so this generation is reflected in our results. In addition, for these units we estimate an extra year's worth of fixed operations and maintenance costs to be around $4 million.[40] This cost is small in comparison to the generation cost increase caused by the SONGS closure. It is also very small in comparison to the fixed operations and maintenance costs at SONGS itself; this is in part because the two Huntington Beach units are smaller, and in part because fixed O&M costs are much lower at natural gas units than at nuclear units.

Whether endogenous or exogenous, a separate concern is that this entry and exit could have affected transmission constraints. In the paper we attribute the increase in transmission constraints observed in 2012 to the SONGS closure. However, suppose, for example, that a large plant had opened in Northern California at exactly the same time that SONGS closed. In this case there would actually be two complementary explanations for the increase in transmission constraints, and it would be misleading to focus entirely on SONGS. As it turns out, net entry during the twelve months following the SONGS closure was larger in the North than the South, by approximately 130 MWh on average per hour. Thus, net entry was in the direction that would have tended to exacerbate transmission constraints. That said, the magnitude of the net entry is small compared to the 2,150 MWh per hour typical generation from SONGS. Moreover, the net entry is also small compared to the year-to-year change in hydro generation. As we report in Table 2, hydro generation in California decreased by 2,000+ MWh per hour (1.51 million MWhs on average per month) between 2011 and 2012. As we reported in Section A1.3, 75 to 80 percent of this decrease occurred in the North. This year-to-year decrease in hydro generation dwarfs the change in net entry, implying that the overall impact of these combined changes to generation (from net entry, hydro, other renewables, etc.) would have been, if anything, to reduce transmission congestion between Northern and Southern California. In short, we conclude that entry and exit cannot provide an alternative explanation for the transmission constraints observed post-closure.

A1.5 Imports

Imports make up 30 percent of total electricity supply in California. In calculating our predicted effects we have implicitly assumed that none of the lost generation from SONGS is met by out-of-state generation. Whether or not this is a reasonable assumption depends on the impact of the SONGS closure on prices and on the elasticity of supply for imports. Our

[40] The Cost of Generation Model from CEC (2010) reports an annual fixed O&M cost for California combustion turbine plants of 8.3 $/kW-yr, in 2010 dollars (it does not report a number for steam boilers). We multiplied this by a capacity of 440 MW and translated into current dollars.

results suggest that price impacts were likely modest. During most hours equilibrium in the California electricity market occurs along the long inelastic part of the marginal cost curve, so one would not have expected the SONGS closure to have a substantial impact on prices. In addition, during the hours in which equilibrium occurs along the steep part of the marginal cost curve, imports were largely unresponsive.

Empirically, the elasticity of supply for imports appears to be relatively low. As shown in Figure 3, imports increase with system demand, but not very much, and most of the increase occurs at relatively low demand quantiles. Above the median system-wide demand, there is essentially no observable increase in imports. Averaging across all hours, imports increase by an average of 519 megawatt hours when total demand increases by 2,150 MWh. This is equivalent to 25 percent of the lost generation from SONGS. This suggests that we could reduce our predicted estimates in Panel A of Table 3 by 25 percent. For the cost estimates, however, we do not expect much of an adjustment needs to be made. Since the in-state generation marginal cost curve is quite elastic in most hours, the cost of out-of-state generation must have been close to the marginal cost of the in-state generation. As a result, the cost estimates we report in the paper should be close to the true change in total cost accounting for imports.

Interestingly, the change in imports during weekday summer afternoons and high demand hours was much lower. During weekday summer afternoons, imports in 2012 increased on average by only 90 megawatt hours, and during high demand hours the increase was less than 10 megawatt hours. This is consistent with interstate transmission constraints or other physical limitations of the grid preventing larger increases in imports during these hours. Alternatively, it could simply reflect the fact that demand is correlated across states, i.e. it tends to be hot in Nevada and California at the same time, and so the elasticity of supply for imports becomes very inelastic in these periods.

From the perspective of interpreting our results it doesn't particularly matter *why* imports are not responding more. This lack of responsiveness in high demand hours means that the estimates in Panels B and C of Table 4 are approximately correct. Incorporating imports would reduce our estimates in these panels by only 4 percent and 1 percent, respectively, reflecting the relatively small portion of the lost generation from SONGS that appears to have been met with imports.

A1.6 Electricity Demand

Statewide demand for electricity was slightly higher in 2012 than 2011 due to warm weather. We calculate our predicted effects using the distribution of system-wide demand in 2012, so our estimates reflect this higher overall level of demand. Hence, there is no sense in which this aggregate change in electricity demand is biasing our estimates. Still, in the paper, we would like to attribute the increase in transmission constraints to the SONGS closure, so it would be worth knowing if the changes in electricity demand are large enough to provide an alternative explanation.

Had SONGS closed during a cooler year, it would have been less expensive to meet the lost generation, and transmission constraints would have been less binding. While this is undoubtedly true, the same could be said about hydroelectric generation, natural gas prices, and other factors. Throughout the analysis we have tried where possible to have our estimates reflect actual market conditions in 2012.

A related question is how to think about demand response. Implicitly, our analysis assumes that electricity demand is perfectly inelastic. We calculate our predicted effects by moving along the generation curves by 2,150 MWhs, the entire lost generation from SONGS. This assumes that demand is perfectly inelastic. Although this assumption is common in the literature, it is obviously not exactly right. Although the vast majority of customers do not face real-time prices, retail electricity prices do respond month-to-month to change in generation costs. Moreover, there are some industrial customers who face prices that update more frequently. The size of the demand response depends on how much prices changed and the price elasticity of demand. The SONGS closure shifts the marginal cost curve to the left, increasing prices. Our results suggest, however, that in the vast majority of hours this price impact would have been fairly modest, because demand was crossing a fairly elastic portion of the marginal cost curve. Moreover, most estimates of the price elasticity of demand[41] suggest that even in the medium-term, demand is not very elastic.[42] Thus evaluating the change in supply required to make up the entire 2,150 MWhs of lost generation is likely a very good approximation.

A more subtle concern is whether differential changes in demand across region could have impacted transmission constraints. To evaluate this, we obtained hourly demand for three geographic regions within California, corresponding closely to the Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric service territories (the former in the North, and the latter two in the South). In Figure A4, we show the total weekly quantity demanded for all three regions across time. While not large, there does appear to be a divergence in the summer of 2012 between the PG&E and SCE quantities, reflecting

[41] Ito (2014), for example, finds a price elasticity of less than -0.10 with respect to retail prices for a sample of California households.

[42] There are also explicit "demand response" programs operated by the three California investor-owned utilities. The use of these programs increased between 2011 and 2012, but from a very low baseline level. Total estimated demand reductions from of all California demand response programs in 2012 was 25,882 megawatt hours (CAISO 2013b, p. 34). This is less than 0.01 percent of total electricity in the market, and equivalent to only 12 *hours* of generation from SONGS. Moreover, there are serious challenges with these programs that limit CAISO's ability to effectively target modest resources to hours and locations when and where they would be most valuable (CAISO 2013b, pp. 35–37).

a warmer than average summer in the South. However, in Figure A5, we show preliminary evidence that this is unlikely to explain much of the price difference we see in the post-period. This graph plots the price difference between the SP26 and NP15 pricing regions, as well as the demand difference between the South (SCE plus SDG&E) and the North (PG&E). While the demand difference between the North and South increased in late 2012, the price difference increased much sooner and persisted much longer.

To more formally address the concern that our residual results could have been driven by the changes in demand, we examined results from an alternative specification in which we estimate equation (1) conditioning on the demand *difference* between North and South. Specifically, we calculate the difference between South (SCE plus SDG&E) and North (PG&E), then construct a series of equal-width bins. These bins are interacted with the demand bins in the unit-level generation regressions. The predicted results (available upon request) are qualitatively similar to those in Table 3. The point estimates of the residual results are generally around 10 percent smaller than in Table 3, although they are not statistically different. This may indicate that a small portion of the congestion was attributable to the difference in demand.

A1.7 Placebo Tests for Residual Effects

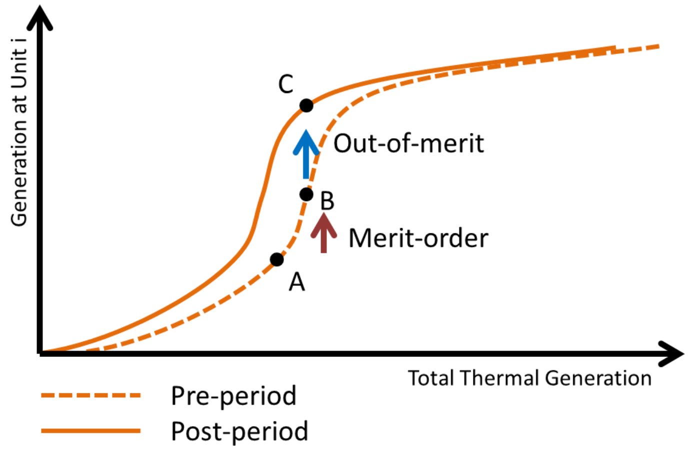
To provide further evidence that the observed residual effects are unusual, and not driven by idiosyncratic unobservables, we next provide a series of placebo tests. We repeat our analysis six times, estimating the model as if SONGS had closed in different years (2006, 2007, ... and 2011). Figure A6 shows the residual changes for each placebo, with separate results (as in our main analysis) for all hours, weekday summer afternoons, and high demand hours.

The figure shows that some of the estimated residual effects from other years are similar in size to the estimates for 2012. In 2007, for instance, the South saw positive residual changes, whereas the North saw negative changes. However, the results for 2012 differ more dramatically from the placebo results when one accounts for the unusual behavior at AES-owned facilities. In Figure A7, we again show six placebo tests, but based on estimates from a sample that excludes AES. In these results, the 2012 large positive changes in the South and large negative changes in the North are more apparent than in the previous figure.

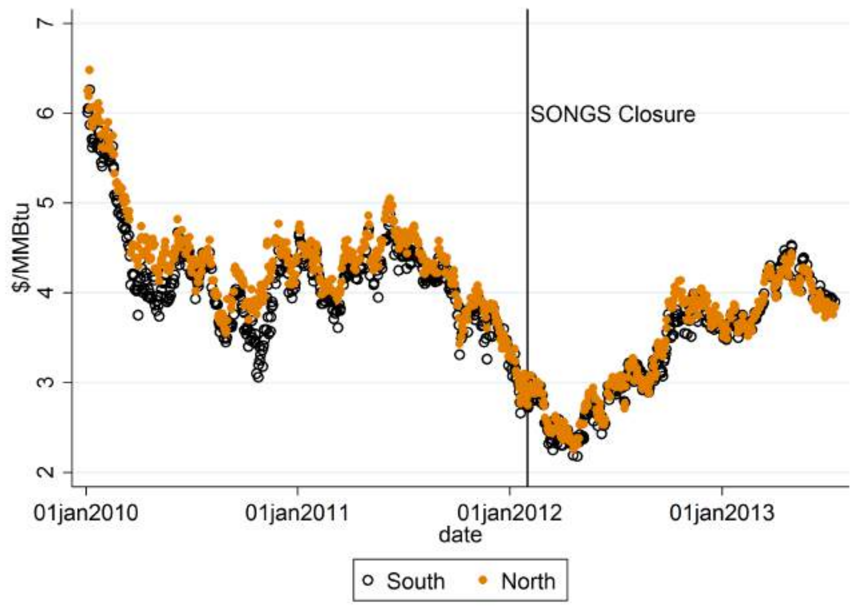
Moreover, closer inspection of the residual results in other years shows that they are largely driven by extended outages at single plants, rather than by correlated changes across plants. To demonstrate this, Figure A8 shows a series of additional statistics from these placebo tests. In particular, we calculate the standard deviation, skewness, and kurtosis of our estimated unit-level residuals. For years with the largest average residuals by zone (especially 2007 and 2009), the presence of outliers is clear in these diagnostics. These years have higher standard deviations, skewness (in absolute terms), and kurtosis than our main sample, indicating the presence of outliers.

We also calculate the residual change in generation costs implied by each placebo. As we report in Table 5, our estimate is \$40 million per year. This estimate is higher than all six estimates based on placebos, but in some placebo samples the estimate is close in magnitude to \$40 million. This reflects extended outages at different plants and other unmodeled year-to-year changes in the market. Overall, the placebo test results indicate that the pattern of generation and cost results we see in 2012 is indeed unusual, though not significantly outside of the range observed in other years. None of this calls into question the estimated first-order effects (i.e. the \$311 million increase in generation costs), but it suggests that the residual effects should be interpreted cautiously.

Appendix Figure A1: Predicted and Residual Effects



Appendix Figure A2: Natural Gas Prices, by Region



Note: This figure plots daily natural gas prices, in $/mmbtu, for Northern California (PG&E citygate) versus Southern California (SCG citygate). Data are from Platts Gas Daily.

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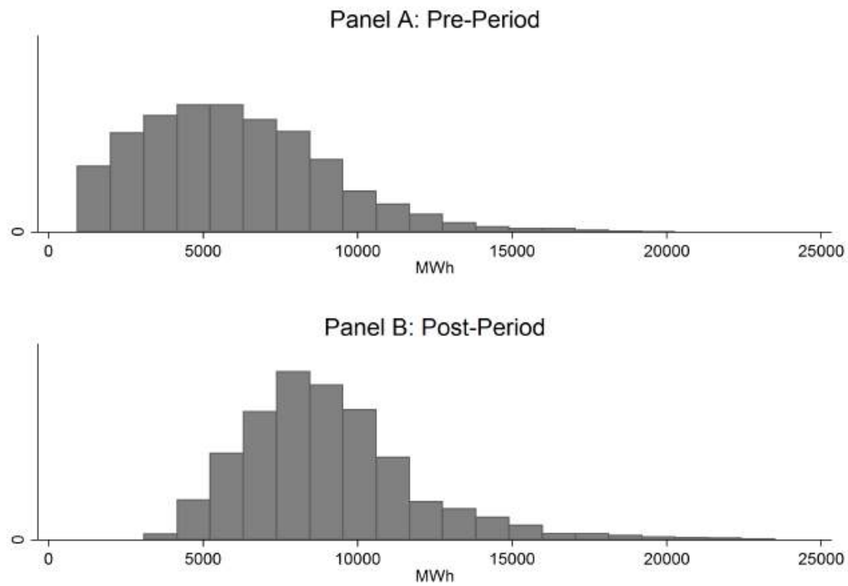
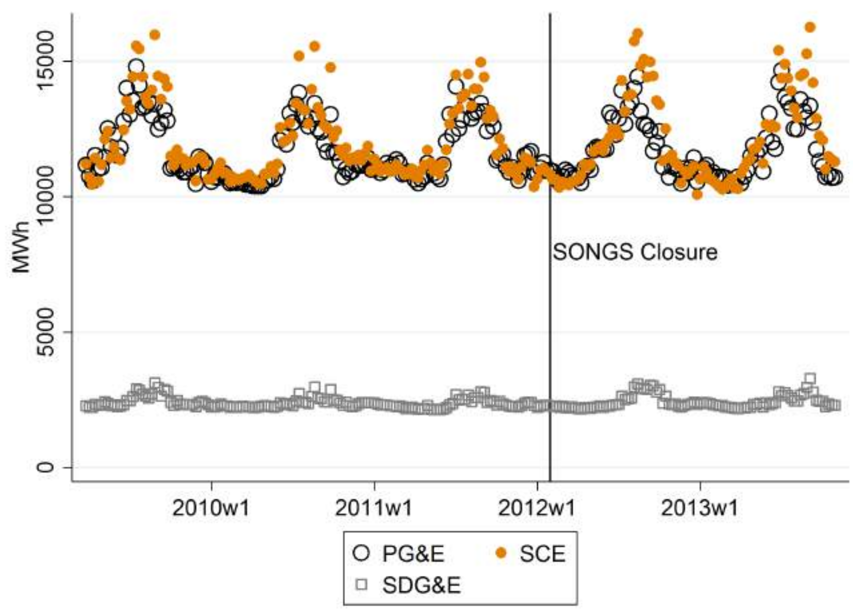
Appendix Figure A3: Histogram of Hourly Total CEMS Generation



Note: This figure shows histograms of total hourly generation from CEMS units in the year leading up to the SONGS closure (Panel A) and in the year following the closure (Panel B). The shift to the right in Panel B reflects both the closure of SONGS and concurrent changes in non-thermal generation (especially hydro) and demand.

Appendix Figure A4: Regional Demand



Note: This figure plots average hourly quantity demanded by week for the three California investor-owned utilities. The vertical line shows the week the second SONGS unit went down. PG&E is roughly the Northern half of the state, SCE is the Southern half excluding the San Diego area, and SDG&E is the San Diego area.

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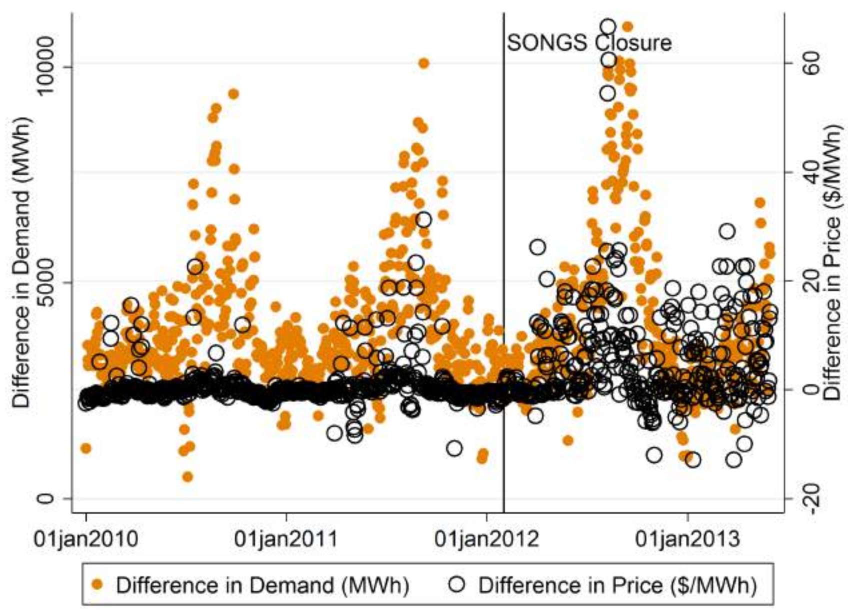
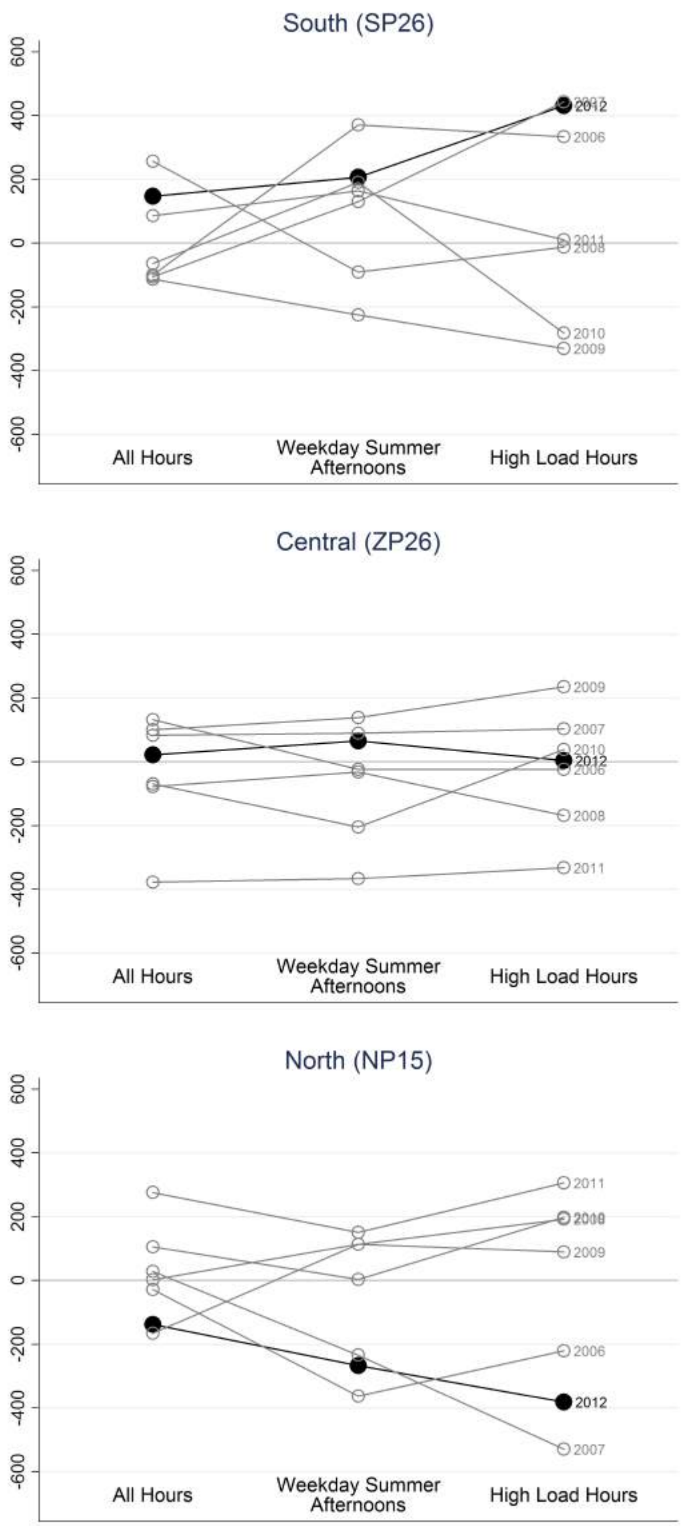
Appendix Figure A5: Regional Demand and Price Differentials



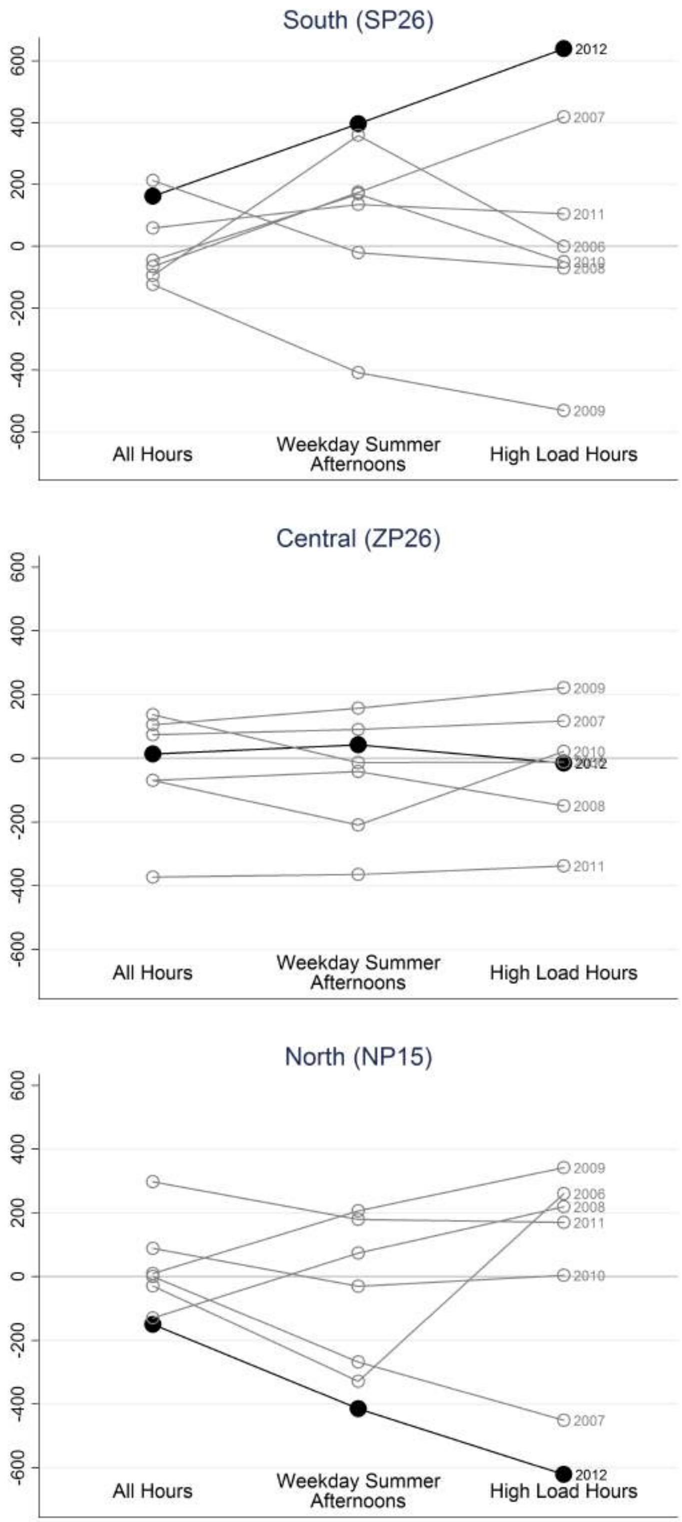
Note: This figure plots quantity demanded and price differentials at 3 pm daily between January 2009 and September 2013. Weekends are excluded. The vertical line shows the day the second SONGS unit went down (February 1, 2012).

Appendix Figure A6: Residual Changes, by Year



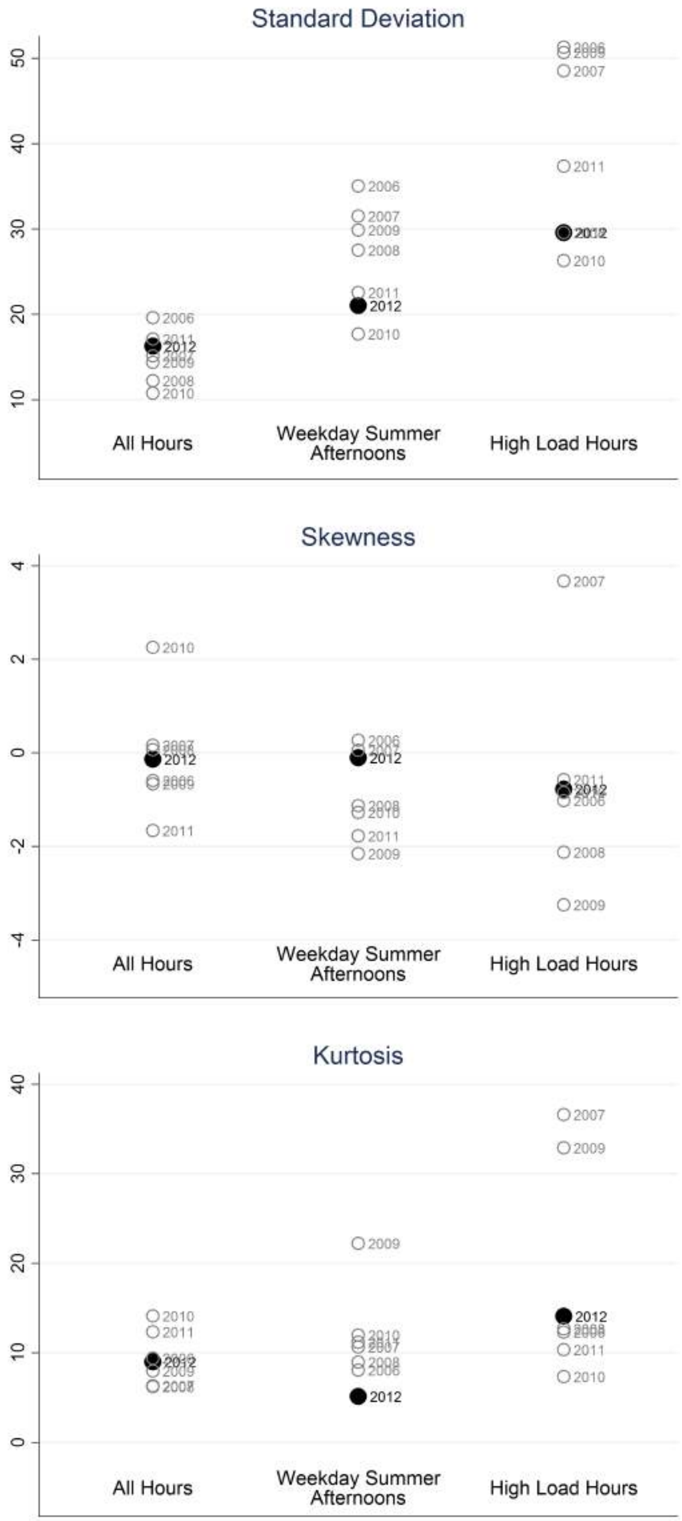
Note: These figures show residual estimates for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A7: Residual Changes, without AES, by Year



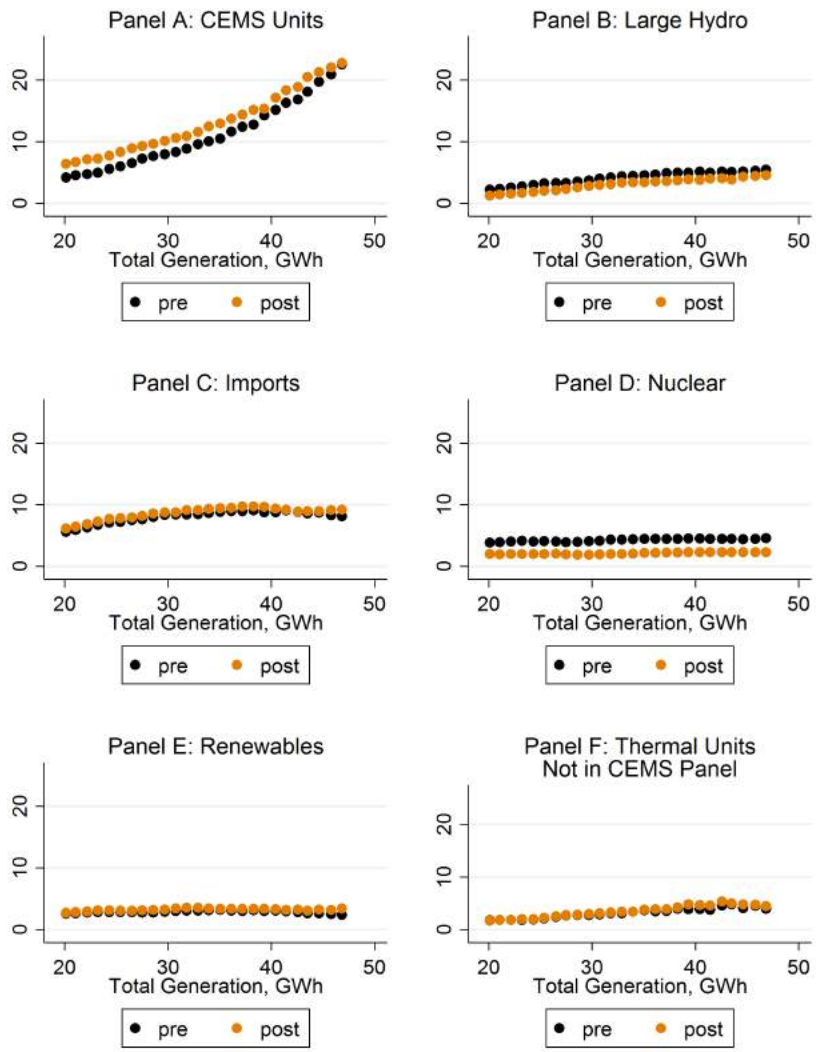
Note: These figures show residual effects based on estimates from a sample that excludes AES plants for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A8: Unit-Level Diagnostics, by Year



Note: These figures show unit-level diagnostics on the residual estimates, for the main sample of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A9: Generation Regressions by Category



Note: This figure was constructed in the same way as Figure 3 in the main text, but using data from both the pre-period and the post-period. The x-axis shows the quantile of total generation from all sources and the y-axis shows the average generation, in MWh, for that category of generation.

Appendix Table A1: California Electricity Generation By Source, 2011

Category	Subcategory	Percentage
Fossil Fuels	Natural Gas	44.3
	Coal	1.0
	Other Fossil Fuels	1.7
	Total	**47.0**
Nuclear	San Onofre	9.0
	Diablo Canyon	9.2
	Total	**18.3**
Renewables	Hydroelectric	21.1
	Geothermal	6.3
	Wind	3.9
	Solar (PV and Thermal)	0.4
	Other Renewables	3.0
	Total	**34.7**
Total		**100.0**

Note: These data come from the U.S. Department of Energy *Power Plant Operations Report*, which reports net generation from all electric generating plants larger than one megawatt. We include all facilities operating in California. “Other Fossil Fuels” includes petroleum coke, distillate petroleum, waste oil, residual petroleum, and other gases. “Other Renewables” includes wood, wood waste, municipal solid waste, and landfill gas.

Appendix Table A2: Largest Plants not in CEMS

Plant Name	Operator	Sector	Prime Mover	County	Fuels	Million MWh in 2011	Million MWh in 2012	Summer Capacity, MW	Capacity Factor, 2011	Vintage
Panel A: Non-Cogen Natural Gas Plants										
Humboldt Bay	PG&E	Utility	Internal Combust.	Humboldt	Natural Gas, Petroleum	0.5	0.4	167	0.32	1956*
Wheelabrator Shasta	Wheelabrator Environmental Systems	IPP	Steam Turbine	Shasta	Wood Waste	0.4	0.4	60	0.74	1987
Desert View Power	Desert View Power Inc	IPP	Steam Turbine	Riverside	Wood Waste, Nat. Gas, Tires	0.3	0.3	47	0.83	1991
SEGS IX	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.29	1990
SEGS VIII	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.28	1989
Panel B: Cogen and Industrial Natural Gas Plants										
Watson Cogeneration	ARCO Products Co-Watson	Industrial	Combined cycle	Los Angeles	Nat. Gas, Other Gases, Waste Oil	3.0	3.1	398	0.86	1987
Crockett Cogen Project	Crockett Cogeneration	IPP Cogen	Combined cycle	Contra Costa	Natural Gas	1.8	1.7	247	0.84	1995
Sycamore Cogeneration	Sycamore Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.5	1.4	300	0.57	1987
Midway Sunset Cogen	Midway-Sunset Cogeneration Co	Industrial	Gas turbine	Kern	Natural Gas	1.4	1.4	219	0.72	1989
Kern River Cogeneration	Kern River Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.3	1.3	288	0.50	1985
Panel C: Other Plants										
Diablo Canyon	PG&E	Utility	Steam Turbine	San Luis Obispo	Nuclear	18.6	17.7	2240	0.95	1985
San Onofre	SCE	Utility	Steam Turbine	San Diego	Nuclear	18.1	0.8	2150	0.96	1983
Geysers Unit 5-20	Geysers Power Co LLC	IPP	Steam Turbine	Sonoma	Geothermal	4.7	4.8	770	0.70	1971
Shasta	U S Bureau of Reclamation	Utility	Hydro	Shasta	Hydro	2.4	1.8	714	0.38	1944
Edward C Hyatt	CA Dept. of Water Resources	Utility	Hydro	Butte	Hydro	1.9	1.4	743	0.30	1968

Note: These data come from the U.S. Department of Energy *Power Plant Operations Report* and *Annual Electric Generator Report*. The table describes 2011 net generation for plants operating in California. "Largest" is defined according to net generation reported to EIA in 2011. Vintage refers to the year the plant started commercial operation. *Humboldt Bay was in CEMS until 2010 but dropped out after that, when the all of the plant's combustion turbine and steam boiler units were replaced with reciprocating engine generators.

Appendix Table A3: Most Affected Plants, All Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Predicted Change (MWhs)	Residual Change (MWhs)
			Panel A. Predicted Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	227	59
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	168	100
3	Pastoria	Calpine	Comb Cyc	SP15	25/26/26	764	142	-37
4	Delta	Calpine	Comb Cyc	NP15	26/27/27	896	126	25
5	Mountainview	SCE	Comb Cyc	SP15	25/26/26/26	1068	126	3
			Panel B. Residual Increases, Top Five					
1	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	54	143
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	168	100
3	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	23	87
4	High Desert	Tenaska	Comb Cyc	SP15	39/39/40	492	91	82
5	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	227	59
			Panel C. Residual Decreases, Top Five					
1	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	101	-114
2	Inland Empire	General Electric	Comb Cyc	SP15	24/25	752	61	-111
3	Calpine Sutter	Calpine	Comb Cyc	NP15	25/26	564	101	-94
4	Gateway	PG&E	Comb Cyc	NP15	27/27	590	84	-72
5	Cosumnes	SMUD	Comb Cyc	NP15	26/26	523	41	-41

Note: The regressions for this table are identical to those in Table 3, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in our sample. †EME refers to Edison Mission Energy.

Appendix Table A4: Most Affected Plants, Weekday Summer Afternoons

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Predicted Change (MWhs)	Residual Change (MWhs)
			Panel A. Predicted Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	236	43
2	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
3	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
4	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
5	AES Redondo	AES	Boiler	SP15	40/444/55/64	1348	88	-67
			Panel B. Residual Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	36/38/38/38/41/42	636	30	158
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
3	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
4	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	54	98
5	Elk Hills	Occidental Petroleum	Comb Cyc	ZP26	26/27	548	11	86
			Panel C. Residual Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
2	Panoche	Energy Investors Fund	Combust Turbine	NP15	35/35/35/35	412	54	-105
3	Calpine Sutter	Calpine	Comb Cyc	NP15	25/26	564	60	-94
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/38	186	28	-80
5	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	25	-76

Note: The regressions for this table are identical to those in Table 3, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in the CEMS data. Weekday summer afternoons include the hours 2 p.m. to 5 p.m. in months June through September. †EME refers to Edison Mission Energy.

Appendix Table A5: Most Affected Plants, High Demand Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Predicted Change (MWhs)	Residual Change (MWhs)
			Panel A. Predicted Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	251	-62
2	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	238	-196
3	AES Redondo	AES	Boiler	SP15	40/44/55/64	1348	130	-122
4	El Segundo	NRG	Boiler	SP15	41/42	658	130	113
5	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	124	154
			Panel B. Residual Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	36/38/38/38/41/42	636	33	257
2	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	124	154
3	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	10	117
4	El Segundo	NRG	Boiler	SP15	41/42	658	130	113
5	Ormond Beach	NRG	Boiler	SP15	40/41	1490	98	108
			Panel C. Residual Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	238	-196
2	AES Redondo	AES	Boiler	SP15	40/44/55/64	1348	130	-122
3	Panoche	Energy Investors Fund	Combust Turbine	NP15	35/35/35/35	412	53	-116
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/38	186	33	-97
5	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	21	-77

Note: The regressions for this table are identical to those in Table 3, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in our sample. High demand hours are defined as hours when total CEMS generation was in the 13th quantile (greater than 13,837 MWh). †EME refers to Edison Mission Energy.

Appendix Table A6: Separating Alamitos and Redondo

	Average Hourly Change, By Region			
	AES	Southern California, Excluding AES	Central California	Northern California
	(1)	(2)	(3)	(4)
	Panel A: All Hours			
Predicted Change (MWh)	110	781	300	944
	(15)	(15)	(15)	(18)
Residual Change (MWh)	-32	182	20	-140
	(60)	(53)	(66)	(49)
	Panel B: Weekday Summer Afternoons			
Predicted Change (MWh)	339	729	259	822
	(31)	(27)	(17)	(39)
Residual Change (MWh)	-311	548	76	-260
	(94)	(105)	(61)	(119)
	Panel C: High Demand Hours			
Predicted Change (MWh)	455	752	174	753
	(42)	(34)	(30)	(35)
Residual Change (MWh)	-310	742	4	-381
	(127)	(111)	(57)	(129)
Observations (Hour by Unit)	340,340	1,944,800	267,410	1,920,490
Number of Generating Units	14	80	11	79
Number of Plants	3	39	5	43
Total Capacity (MW)	4,167	11,755	2,887	11,776

Note: The format of the table and underlying data are identical to Table 3, but we have separated plants owned by AES from other Southern plants. The three AES plants are Alamitos, Redondo Beach, and Huntington Beach. AES and JP-MorganChase had tolling agreements for all three plants.

Appendix Table A7: Including 2013

	Average Hourly Change, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Predicted Change in Net Generation (MWh)	883	301	950
	(19)	(17)	(18)
Residual Change in Net Generation (MWh)	63	40	-78
	(77)	(70)	(75)
	Panel B: Weekday Summer Afternoons		
Predicted Change in Net Generation (MWh)	1037	278	853
	(43)	(15)	(35)
Residual Change in Net Generation (MWh)	191	22	-193
	(126)	(77)	(107)
	Panel C: High Demand Hours		
Predicted Change in Net Generation (MWh)	1214	183	748
	(41)	(29)	(36)
Residual Change in Net Generation (MWh)	390	-15	-348
	(141)	(61)	(131)
Observations	2,565,420	306,735	2,202,915
Number of Generating Units	92	11	79
Number of Plants	42	5	43
Total Capacity Represented (MW)	15,498	2,935	11,782

Note: This table was constructed in the same way as Table 3, except that data were also included for February through June of 2013.