Tab 1

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From: TerKeurst, Charlotte <charlotte.terkeurst@cpuc.ca.gov>
Sent: Friday, February 07, 2014 5:02 PM
To: Picker, Michael; Chaset, Nicolas L.
Subject: FW: Voting Meeting 90-Day Outlook (INTERNAL Use only)
Attachments: 90 Day Outlook 02 04 14 INTERNAL.doc

Here is the most recent 90 day outlook of expected issues to be on the CPUC agenda.

From: Prosper, Terrie D.
Sent: Monday, January 27, 2014 2:45 PM
To: Prosper, Terrie D.
Subject: Voting Meeting 90-Day Outlook (INTERNAL Use only)

Commissioners, Advisors, and Directors,

Attached and pasted below is the latest edition of our Voting Meeting 90-Day Outlook (for internal use only), which highlights key issues set for discussion at our upcoming Voting Meetings. Also included is a list of upcoming reports and possible FCC filings.

Please let me know if you have any questions or if you have suggestions about how to make this document more useful to you.

Thanks,

Terrie

Voting Meeting and Reports 90-Day Outlook: Feb.-April 2014

Voting Meeting of Feb. 5, 2014 – Energy

Rulemaking on Fire Safety (R.08-11-005)
Proposed Decision addresses issues in Phase 3, Tracks 1 and 2. Specifically, the Proposed Decision considers whether to adopt: 1) Approximately 50 proposals by the parties to revise General Order 95 in ways that are intended to reduce the fire hazards associated with overhead power lines and aerial communication facilities located in close proximity to power lines; and 2) A framework for investor-owned electric utilities to collect and report data to the CPUC's Safety & Enforcement Division (SED) regarding power-line fires, and for SED to identify and assess systemic fire-safety risks associated with overhead power line facilities and aerial communications facilities in close proximity to power lines. (Florio/Kenney)

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Resolution T-17428 seeks approval for a California Advanced Services Fund project (Ponderosa Cressman).

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Voting Meeting of March 13, 2014 – Energy

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• Resolutions seek approval to fund four separate California Advanced Services Fund projects (Schat, ViaSat, Bright Fiber Network, Shasta County Telecom). • Resolution T-17312 (Ducor) addresses a rehearing decision.

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Tab 2

Message

From: Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Sent: 2/11/2014 5:04:10 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Subject: SONGS briefing docs

Michael
Attached are the SONGS briefing docs on dropbox. Thought you might want them in a more easy to access format.

Tab 3

Message

From: Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Sent: 2/12/2014 4:49:01 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Subject: SONGS documents
Attachments: Briefing on NUCLEAR ISSUES by ED staff.doc; PD re Phase 1 2012 SONGS Expenses.pdf; SONGS briefing doc from ALJs Darling & Dudney.doc; SONGS PD Summary of Party Comments chh.docx; SONGS Phase 1 PD Summary chh.docx

Nicolas Chaset
Special Advisor for Distributed Energy Resources
Office of Governor Edmund G Brown, Jr
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

Briefing on NUCLEAR ISSUES
(by ED staff)

Nuclear Power Plants: Size and Ownership

- PG&E owns Diablo Canyon Power Plant (DCPP Units 1 and 2 located near San Luis Obispo and Humboldt Bay Power Plant (HBPP) Unit 3 near Eureka CA.

    1. DCPP 1 and 2 are operating plants generating approx 1100 MW each.
    2. HBPP 3, a 63-MW boiling water reactor is currently being decommissioned.

- SCE owns 78.21% of San Onofre Nuclear Generating Station (SONGS) located adjacent to Camp Pendleton near San Clemente CA.

    1. SONGS 2 and 3 rated at 1120 MW each; currently permanently shutdown due to steam generator problems and slated for decommissioning to begin mid-2015.
    2. SONGS 1 is being decommissioned since 1999.

- SDG&E owns 20% and the City of Riverside owns 1.79% of SONGS 1, 2, and 3.

- SCE owns 16.5% of Palo Verde Nuclear Generating Station. This three-unit nuclear plant is located near Phoenix Arizona.

- Operating license termination dates: DCPP 1 2024; DCPP 2 2025; SONGS 2 & 3 2022; Palo Verde 1 2044; Palo Verde 2 2046; Palo Verde 3 2047. In April 2011, the NRC granted 20-year license extension to Palo Verde.

- The Nuclear Regulatory Commission (NRC) has jurisdiction over the licensing, safety, and operational aspects of nuclear power plants. The CPUC has jurisdiction primarily related to cost issues.

Steam Generator Replacement at SONGS

- In 2005 D.05-12-040, the CPUC authorized total spending of $680 million (2004 dollars) for the steam generator replacement project (SGRP) for SONGS 2 and 3 including removal of the original 2 SGS in each unit and disposal. D.11-05-035 reduced the amount to $671 million.

- As of June 30, 2012, SCE's investment in the SGRP is $593 million, and SDG&E's investment is $178 million.

    1. The CPUC will review the reasonableness of the actual SGRP expenditures including disposal upon submission of SCE's final costs for the project.

    2. That submission originally planned for late 2012 is now expected March 15, 2013 and be incorporated into Phase 3 of the SONGS OII.

    3. D.05-12-040 authorized recovery of revenue requirements associated with the SGRP in rates after each unit went back into operation.

- SONGS 2 steam generator replacement was completed on April 11, 2010, and revenue requirements associated with the Unit 2 SGRP were recorded in balancing accounts at that time. SCE included $97 million and SDG&E included $18 million in 2011 rates. SCE included $60 million and SDG&E $18 million in 2012 rates associated with the SGRP for SONGS 2.

- The Unit 3 SGRP was completed on Feb 18, 2011, and revenue requirements associated with Unit 3 were recorded in balancing accounts at that time.

    1. SCE included $101 million in 2012 rates associated with the replacement of the Unit 3 SGs.

    2. SDG&E included $14 million in 2012 rates associated with the replacement of the SGS for SONGS 3.

    3. Thus, the total recovery included by SCE in 2011 and 2012 for SG replacement is $258 million and the total included by SDG&E is $50 million. The total for both utilities for the SGRP already in rates so far is $308 million.

- On March 8, 2013, the NRC released to the public the non-proprietary version of the MHI root cause analysis report it prepared in 2012.

- SCE submitted its application A.13-03-005 on March 15, 2013 for the actual costs of the SONGS steam generator replacement project (SGRP) including removal and disposal of the four old steam generators. SCE indicated it spent $768.5 million in nominal dollars for the SGRP. SDG&E also submitted an application A.13-03-014 for its share of the SGRP costs, above. The costs associated with the SGRP will be addressed in Phase 3 of the SONGS OII beginning 2014.

- On May 4, 2013, the ASLB ruled that SONGS 2 cannot restart until the NRC holds a formal license amendment proceeding with full public participation.
- On June 7, 2013, SCE notified the NRC that it will permanently shutdown SONGS Units 2 and 3.
- On July 18, 2013, SCE submitted a Notice of Dispute to Mitsubishi seeking recovery of costs for the replacement steam generators that lead to the shutdown of SONGS 2 and 3.
- On Sept. 20, 2013, the NRC issued an inspection report preliminarily indicating potential violations related to the SONGS steam generators. A white finding of low to moderate safety significance against Unit 3 for inadequate design of the SGs and a green non-cited violation for Unit 2 because the tubes did not actually leak. The NRC also issued a Notice of Non-Conformance to Mitsubishi.
- On Oct.21, 2013, SCE replied to the NRC that it agreed with the NRC's inspection findings and level of violation.

<u>SONGS OII I.12-10-013:</u>

- OII I.12-10-013 initiated because SONGS 2 and 3 have been non-operational since January 2012 due to steam generator issues.
- SONGS 3 fuel removed from reactor and placed in wet fuel storage pool. SONGS 3 is not expected to restart with the existing defective steam generators.
- In Oct 2012, SCE applied to the NRC to restart and operate SONGS 2 at 70% power. This application is still under review by NRC. The NRC has issued 67 Requests for Additional Information. NRC expected to issue a decision in June 2013.
- Assigned ALJ Melanie Darling and Commissioner Florio.
- Prehearing conference held on Jan 8, 2013.
- Public Participation Hearing Feb 21 in Costa Mesa. An additional PPH is scheduled for Oct. 1, 2013 in San Diego.
- Initial testimony filed by SCE and SDG&E Dec 17, 2012.
- Additional testimony filed Jan 9, 2013.
- Scoping memo for Phase 1 issued Jan 28, 2012. Allows for collaboration with CA Energy Commission.
- SONGS OII will have 3 or 4 phases. Each phase will have its own PHC and scoping memo.

1. Phase 1 – Scope includes the nature and effects of the steam generator failures in order to assess the reasonableness of SCE's consequential actions including removal of fuel from unit 3; reasonableness of SONGS-related expenditures incurred in 2012 including replacement power; reasonableness of expenditures for community outreach and emergency preparedness related to the SONGS outage; and if any rates preliminarily approved in the 2012 GRC should be refunded SCE and SDG&E established SONGS Outage Memorandum Accounts to record 2012 expenditures incurred since Jan 1, 2012 per the OII. Phase 1 expected to be concluded by Fall 2013.
2. Phase 2 – Envisioned to address issues related to any reductions to SCE's rate base. Phase 2 expected to be concluded by the end of 2013 with a decision by Feb 2014.

3. Phase 3 - Envisioned to address the causes of the steam generator damage, allocation of responsibility, reasonableness of the steam generator replacement costs and possibly how any liability issues between SCE and Mitsubishi are resolved. SCE filed in March 2013 the actual costs incurred for the steam generator replacement and disposal of the old SGs. Approximately $260 million is already in rates, but subject to reasonableness review and refund. Phase 3 expected to begin in early 2014.
4. Phase 4 – This phase might be needed to address adjustments to SCE's 2013 revenue requirement to reflect lower than forecast O&M expenses, capital spending, replacement power, and other SONGS expenses.

- Phase 1 Scoping memo issued Jan 28, 2013. Allows for collaboration with CA Energy Commission.
- ED to provide staff support for Demand Response, Replacement Procurement, Energy Efficiency issues in Phase 1.
- Phase 1 testimony filed by parties on Mar.29, 2013.
- Hearings for Phase 1 held May 13 – 17, 2013.
- Additional Phase 1 hearings on additional testimony on replacement power held Aug. 5-6, 2013.
- Phase 2 Pre-hearing conference held July 12, 2013.
- PPH held on Oct. 1, 2013 in San Diego.
- Phase 2 hearings held Oct. 7 – 11, 2013.
- The PD for Phase 1 is was mailed on Nov. 19, 2013 to be on the Dec 19, 2013 Commission agenda.
- A two-year contract was approved for Dr. Robert Budnitz to be an expert consultant to Energy Division on technical issues primarily the steam generator issues of Phase 3 of the SONGS OII.
- Phase 3 of the SONGS OII expected to begin in Feb. 2014.

Decommissioning

- In accordance with NRC regulations, all nuclear plant owners are required to maintain trust funds to ensure sufficient amounts will be available to decommission their nuclear plants.
- PG&E maintains trust funds for DCPP 1 and 2 and HBPP 3. The trust fund balances as of June 2013 are HBPP 3 - $222 million; DCPP 1 - $925 million; DCPP 2 - $!,288 million
- SCE maintains trust funds for SONGS 1, 2, and 3. The trust fund balances as of June 2013 are SONGS 1 - $206 million; SONGS 2 - $1,287 million; SONGS 3 - $1,451 million
- SDG&E maintains trust funds for its 20% ownership of the SONGS. The trust fund balances as of June 2013 are SONGS 1 - $100 million; SONGS 2 - $347 million; SONGS 3 - $401 million.
- SCE maintains trust funds for its 16.5% ownership of Palo Verde.
- Forecasts of expected decommissioning costs are reviewed every three years at the CPUC during the Nuclear Decommissioning Cost Triennial Proceeding (NDCTP).
- On Dec 21, 2012, PG&E, SCE, and SDG&E filed applications in the 2012 NDCTP A.12-12.-012 with updated decommissioning plans and costs.
- A.12-12-012 assigned to ALJ Darling and Commissioner Ferron.
- PHC for A.12-12-012 set for March 27, 2013.
- In accordance with D.13-01-039 from Phase 2 of the 2009 NDCTP, PG&E can submit Tier 2 advice letters for authorization to disburse funds from the trusts for decommissioning activities for HBPP 3 in accordance with the decommissioning plans. Decommissioning of HBPP 3 is about 50% complete.
- D.13-01-039 allows for increase in investments in stocks and lower rated – higher yield domestic and foreign bonds to increase the overall yield of the trust funds.
- In accordance with a 1999 decision, SCE can disburse funds from its trust for decommissioning SONGS 1 without prior notification to the CPUC as long as the

disbursements are within the forecasted amounts approved in the latest NDCTP. Decommissioning of SONGS 1 is about 90% complete.

- By end of 2013, HBPP decommissioning will have approved disbursements of $550 million. Total authorized thru 2020 is $589 million. There remains about $40 million in planned expenditures, based on 2009 decommissioning costs.
- Nuclear decommissioning, storage, and security costs are rising sharply. In the 2012 NDCTP –
    1. PG&E requests additional $500 million for HBPP not included in any previous NDCTP for removal of concrete caisson around reactor vessel 80 feet below grade.
    2. PG&E requests $551 million for DCPP for wet fuel storage and security.
    3. PG&E and SCE assume spent fuel needs to be retained in wet pool for 12 years before transfer to dry cask storage. A shorter period 5 – 8 years would reduce decommissioning costs.
    4. SONGS decommissioning costs estimated at $4.132 billion. This is an increase of $39 million from 2009 NDCTP.
    5. SCE's share of Palo Verde decommissioning cost is $513 million
- March 27, 2013 Pre-hearing conference held.
- A.12-12-012 for PG&E and A.12-12-013 for SCE and SDG&E were consolidated.
- Hearings held Aug. 7-9, 2013 for HBPP Unit 3.This bifurcation is being considered as Phase 1 of the 2012 NDCTP. A separate decision for HBPP 3 is expected by the end of 2013.
- Hearings held Oct. 21-25, 2013 for DCPP, SONGS, and Palo Verde. This will be considered Phase 2 of the 2012 NDCTP with a decision in early 2014.
- SCE submitted testimony on July 22, 2013 for premature shutdown of SONGS 2 and 3, with decommissioning beginning mid-2015.
- Proceeding needs to consider concern over refunds from Dept of Energy for not accepting spent nuclear fuel. HBPP puts credit (about ($135 million) to decom costs in this proceeding. DCPP puts credit (about $150 million) in its GRC. SONGS puts credit ($142 million) in ERRA.
- SCE is expected to submit a detailed site-specific decommissioning plan for SONGS 2 and 3 in 2014, which will be reviewed in the 2015 NDCTP.
- SCE to submit a Post Shutdown Decommissioning Activities Report (PSDAR) to the NRC by June 2015.

<u>Enhanced Seismic Studies and Independent Peer Review Panel (IPRP) for DCPP Independent Peer Review Group (IPRG) for SONGS</u>

- Initially interest in enhanced seismic studies arose because of intent by PG&E and SCE to request from NRC operating license extensions for 20 additional years for DCPP and SONGS.
- CA Energy Commission AB-1632 Report recommended the utilities to perform enhanced seismic studies with 2-D and 3-D seismic surveys in the areas on-shore and off-shore DCPP and SONGS.
- Assigned ALJ Robert Barnett and Commissioner Florio.
- DCPP IPRP established by D.10-08-003.

- SONGS IPRG established by D.12-05-004.
- The CPUC authorized approximately $64 million each for enhanced seismic surveys at DCPP (D.12-09-008) and SONGS (D.12-05-004).
- IPRP / IPRG members consist of technical experts from CEC, Coastal Commission, CA Seismic Safety Commission, CA Emergency Management Agency, CA Geological Survey, CPUC.
- County of San Luis Obispo also represented in IPRP for DCPP seismic studies.
- IPRP and IPRG review 2-D and 3-D seismic studies proposed by PG&E and SCE for on-shore and off-shore areas in vicinity of DCPP and SONGS.
- The CCC denied permit for PG&E to conduct any 3-D surveys off-shore DCPP in 2012, as well as rejected SCE's application for SONGS off-shore seismic studies over concerns related to disruption to marine life during the high energy testing needed to perform 3-D surveys..
- PG&E's application for DCPP license extension at NRC is currently on hold. PG&E filed an application at the CPUC requesting $80 million to cover costs related to re-licensing activities. This application was suspended.
- The latest IPRP / IPRG meetings were held on July 11, 2013.
- IPRP Report No.5 with comments and discussion on Hosgri fault issued Mar. 25, 2013.
- On Mar. 29, 2013 the IPRP held an information meeting with PG&E to review Pt Buchon 2D/3D seismic survey data.
- PG&E's data of the faults around Pt Buchon indicate that the Shoreline Fault is segmented. One of the branches has been named Pt Buchon Fault. While it might be a northern extension of the Shoreline Fault, PG&E is considering it for now as a separately named fault.
- The IPRP meeting with PG&E on June 6 to discuss IPRP draft Report No.6 on seismic ground motion hazards analysis.
- IPRG Report No. 2 issued July 17, 2017 recommending continuation of seismic projects for SONGS.
- IPRP Report No. 6 regarding DCPP site characterization analysis issued August 12, 2013.
- SCE submitted AL 2930-E, which was approved effective Sept 13, 2013,to continue the seismic projects for SONGS except for installations of ocean bottom seismometers and the seabed floor sampling.
- Contracts for continued funding for the IPRP were extended through June 30, 2015.

<u>Diablo Canyon Independent Safety Committee</u>

- The DCISC is charged with reviewing and making recommendations concerning the safety of operations at DCPP.
- The DCISC consists of three members, one each nominated by the Governor, Attorney General, and Chair of CA Energy Commission for a three-year term.
- The position appointed by the Attorney General currently held by Robert Budnitz expires June 30, 2013. He already served two terms on the DCISC.
- Dr. Budnitz expressed interest in being re-nominated and serving a third term. There is also one other candidate who expressed interest.
- Announcement of an opening for this position is posted on the CPUC website. The new appointment would be for the term July 1, 2013 through June 30, 2016.

STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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November 19, 2013

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Ratesetting

TO PARTIES OF RECORD IN INVESTIGATION 12-10-013

This is the proposed decision of Administrative Law Judges (ALJ) Melanie M. Darling and Kevin Dudney. This item is targeted to appear on Agenda No. 3328 for the Commission's December 19, 2013 Business Meeting, but may appear on a later agenda. Interested persons may monitor the Business Meeting agendas, which are posted on the Commission's website 10 days before each Business Meeting, for notice of when this item may be heard. The Commission may act on the item at that time, or it may hold an item to a later agenda.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:jt2

Attachment

Decision **PROPOSED DECISION OF ALJs DARLING and DUDNEY**
(Mailed 11/19/2013)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Southern California Edison Company and San Diego Gas and Electric Company Associated with the San Onofre Nuclear Generating Station Units 2 and 3.	Investigation 12-10-013 (Filed October 25, 2012)
And Related Matters.	Application 13-01-016 Application 13-03-005 Application 13-03-013 Application 13-03-014

DECISION ON PHASE 1 REGARDING 2012 SONGS-RELATED EXPENSES AND EXPENDITURES

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PROPOSED DECISION ON PHASE 1 RELATED TO 2012 SONGS-RELATED EXPENSES AND EXPENDITURES

1. Summary

This decision adopts interim rate reductions for Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) ratepayers as a result of reduced operating costs in 2012 following cessation of generation at San Onofre Nuclear Generating Station (SONGS). The decision orders refunds of approximately $94.0 million for overcollection of these costs.

The Commission has undertaken a multi-phase investigation into the actions and expenses by SCE and SDG&E (collectively Utilities) after a small radiation leak in a new steam generator led to discovery of serious vibration wear that forced both SONGS reactor units offline after January 31, 2012. This decision covers the first two phases which assess the reasonableness of 2012 expenses charged to ratepayers, including those incurred as a result of the outages.

Due to the non-operation of both units during 2012, the Commission declined to give final approval to the Utilities' estimated SONGS-related 2012 expenses in their respective general rate cases. Instead, the Commission deferred final review of that portion of revenue requirement to this investigation. Meanwhile, the Utilities have already collected a range of 2012 costs in rates. The Commission's Order Instituting Investigation ordered SCE and SDG&E to record all SONGS-related expenses, including those recovered in rates and report the expenses to the Commission on a regular basis.

In the 2012 GRC decisions, the Commission preliminarily allowed rate recovery of estimated SONGS Operations and Maintenance (O&M) and capital spending, subject to refund upon later review of recorded costs within the

framework of the reasonableness of SCE's actions (as operator) as events unfolded in 2012. The Phase 1 portion of the decision provides the deferred reasonableness review of 2012 GRC expenses, and other expenses incurred in 2012 as a result of the outages.

The Commission finds that, $273.9 million (2012$, 100% share[1]) in total 2012 Base Operations and Maintenance (O&M) and associated costs, were reasonable and necessary under the circumstances. This is $115 million less than the GRC-authorized amount of $389 million. In addition, we find that $45.1 million in O&M related to the refueling outage of Unit 2 was reasonable because the work was essentially complete before SCE knew the potential for serious damage in Unit 2.

Our review of capital spending determined that $134.1 million of $167.6 million in costs recorded by SCE was reasonable SONGS-related capital spending to safely maintain the plant. Based on excess capital additions, the Commission orders a 20% reduction of net 2012 additions to rate base and corresponding decreases to recovered capital costs. The overall result is the first SONGS-related refund to ratepayers in this investigation.

For SONGS, 2012 was a transitional year. SCE took reasonable steps to investigate the steam generator problems, and to mitigate some costs, as confirmed by the U.S. Nuclear Regulatory Commission. However, we find SCE to be single-minded about its restart plan, and slow to understand the technical challenges and regulatory timeframe required to implement it. SCE's decision to apply resources to a restart plan was the result of an unsound decision-making

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[1] Most SONGS-related costs are reported as total costs, or 100% of the costs. "SCE share" means $78.21% of the total costs; SDG&E share means 20% of the total costs.

process, primarily because SCE did not consider cost effectiveness or alternatives such as putting Unit 2 into preservation mode, or realistically assess the regulatory hurdles blocking a reasonably foreseeable restart. Therefore, the decision adopts interim rate reductions based on removing an approximation of resulting costs.

The Commission orders the immediate refund of the excess rates collected in anticipation of normal operations at SONGS in 2012, which are deemed not just and reasonable given the fact that no generation occurred after January 31, 2012, nor was it likely to occur in 2012. This decision provides interim rate relief to ratepayers, but $122.6 million in other O&M costs related to the steam generators are still subject to final review in Phase 3. The Commission has not yet determined how much of these costs, if reasonable, will be charged to ratepayers because SCE has made insurance and warranty claims for some of the costs, and allegations of SCE fault remain to be examined.

To reach this decision, we reviewed recorded 2012 expenses in light of the nature and effects of the damage and SCE's consequential actions and costs. The decision establishes May 7, 2012 as the date by which SCE knew, or should have known, that the new type of tube wear linked to the tube leak in Unit 3 was also present, to a lesser degree, in Unit 2. Therefore, Unit 2 and Unit 3 would not likely return to normal operations in the short-term. Despite unduly optimistic reports to SCE's Board of Directors, SCE was aware that no submission to the NRC could occur for months, and SCE's internal actions signaled an understanding that repair options were far from developed. Therefore, reductions were primarily based on removal of an approximate SGIR-related revenue requirement, tempered by SCE's regulatory requirements to maintain the plant in a safe manner.

We also order the continued tracking of incremental costs incurred due to the steam generator outages for further review in Phase 3 when the Commission examines the Steam Generator replacement project as a whole. The Utilities shall cease collection of these incremental costs, and these funds shall be separately accounted for, including interest paid as of June 1, 2012 on recorded SGIR-related O&M and capital costs, if already collected in rates.

The Phase 1A portion of today's decision adopts a method for calculating the cost of replacement power in 2012, and orders the utilities to serve exhibits detailing their calculations according to the adopted method. Recovery of the calculated replacement power costs will be decided in Phase 3 of this proceeding.

2. Background

The San Onofre Nuclear Generating Station (SONGS), located adjacent to Camp Pendleton near San Clemente California, is jointly owned by Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and the City of Riverside (with shares of 78%, 20% and 2% respectively).[2] SCE is the plant operator and bills co-owners for their share of costs.

Pursuant to SCE's 2004 application,[3] the Commission authorized the replacement of the four steam generators at SONGS Unit 2 (U2) and Unit 3 (U3),[4] to be followed by utility applications for reasonableness review of the project costs after completion.[5] Mitsubishi Heavy Industries (MHI) designed and

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[2] The City of Riverside is a municipal utility not under the California Public Utilities Commission's (Commission's) jurisdiction.

[3] Application (A.) 04-02-026.

[4] SONGS Unit 1 has been decommissioned.

[5] Decision (D.) 05-12-040 at Ordering Paragraph (OP) 11, as modified by D.11-05-035.

manufactured the replacement steam generators. The steam generators in U2 were replaced and put online in January 2010; U3 steam generators were replaced and put online in January 2011. In reliance on the Commission's decision approving the Steam Generator Replacement Project (SGRP), both Utilities began to recover a portion of the originally approved costs in 2011.

On January 10, 2012, U2 was taken out of service for a scheduled Refueling Outage (RFO) and expected to return to service on March 5, 2012. U3 was taken offline on January 31, 2012, after station operators detected a radiation leak in a steam generator tube. U2 and U3 were offline throughout the rest of 2012. On June 7, 2013, SCE announced it would not seek to restart either SONGS unit.

In February 2012, the first of many inspections and tests identified different types of tube wear in the U2 and U3 steam generators. SCE engaged with the U.S. Nuclear Regulatory Commission (NRC) following the discovery in U3, and NRC conducted an audit of the problem. SCE also undertook its own investigations and inspections. An unknown phenomena, known as tube-to-tube wear was observed in both U2 and U3 by April 27, 2012.

SCE rescheduled the date for completion of the U2 RFO from March 4, 2012 to March 20, 2012, the first of many delays. SCE identified all compromised, or potentially compromised, tubes and plugged or stabilized them. However, the NRC did not allow SCE to restart the units, even at reduced power, during 2012, or thereafter.

As part of their 2012 General Rate Case (GRC), SCE initially sought approval of its total forecast 2012 SONGS-related expenses based on ordinary operating conditions.[6] SCE estimated $389 million ($2012) for 2012 Operations & Maintenance (O&M) (100%), and $189 million for capital expenditures, as well as $45.0 million for each of two scheduled refueling outages. SDG&E requested rate recovery of its 20% pro rata share through its 2012 GRC, in addition to capital costs and other internal SONGS-related expenses.

Both SCE's and SDG&E's GRCs were pending during 2012. However, the evidentiary records closed well before the year ended and all facts were known. During 2012, SCE incurred O&M costs and capital spending even as it became clear that the units would not be restored to service in 2012, a critical change in circumstance. The Commission decided to review all actual 2012 expenses associated with the non-productive plant after they became known, including SCE's operational response to the extended outages.

Pursuant to Public Utilities Code Section 455.5, on November, 1, 2012, the Commission issued an Order Instituting Investigation (OII)[7]:

> This investigation will consider the causes of the outages, the utilities' responses, the future of the SONGS units, and the resulting effects on the provision of safe and reliable electric service at just and reasonable rates.[8]

The OII ordered SCE and SDG&E to each establish a SONGS Outage Memorandum Account (SONGSMA) to track by category all SONGS-related costs and expenditures incurred on or after January 1, 2012, and revenues collected in recovery of those costs. The Utilities were required to categorize

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[6] A.10-11-015.

[7] Unless otherwise indicated, all future statutory references refer to the Public Utilities Code.

[8] Order Instituting Investigation (I.) 12-10-013 at 2.

recorded expenses by certain subaccounts to identify, inter alia, fixed costs, variable costs, SGRP costs, investigation costs, safety-related program costs, replacement generation, repair costs, regulatory costs, etc.[9] A copy of SCE's year-end 2012 report on the SONGSMA (SCE share) is attached hereto as Appendix A; a copy of SDG&E's year-end reports is attached as Appendix B.

In the GRC decisions for both Utilities, the Commission concluded it was in the best interests of ratepayers to preliminarily allow SONGS-related 2012 O&M and capital expenditures that would have been authorized under normal operating conditions. We anticipated that SCE would need to maintain some systems (e.g., cooling) and divisions (e.g., security, environmental safety) in 2012, regardless of operating conditions, as well as apply resources to understand and address the effects and conditions it faced for the future.

We deferred the final reasonable reviews to the OII and ordered these 2012 costs subject to refund. In Decision (D.) 12-11-051, the Commission confirmed its order to SCE and SDG&E to establish memorandum accounts to be harmonized with the OII, for the purpose of tracking all post-2011 SONGS-related costs for subsequent review. Consistent with the OII, the Commission imposed similar orders in the SDG&E GRC decision.[10]

Following the U3 outage, SCE incurred inspection and repair costs for U2 and U3, while it claimed to be developing a short-term restart plan for U2 and exploring long-term plans for both units. These costs are distinct from Base

[9] The Utilities developed a common format but SCE claims it cannot segregate "safety-related" costs on the basis that safety activities cross several budgets and cannot be reasonably identified.

[10] D.13-05-010.

(routine) O&M. In 2012, both SCE and SDG&E also had to purchase power to replace power lost due to the SONGS outages. The methodology to calculate the amount of replacement power purchased is established below.

3. Procedural History

On November 1, 2012, the Commission opened this OII to consolidate and consider issues raised by the extended outages of SONGS U2 and U3.

The OII identified rate recovery issues including: (1) review of all post-2011 O&M costs and capital spending; (2) costs of scheduled RF) and emergent activities; (3) removal of non-useful generation assets from rate base; and (4) various questions around the costs, viability, and prudency of the SGRP approved in D.05-12-040.

Within the OII, the Commission stated its intention to consolidate other proceedings, to be initiated in the future, which would encompass review of the full range of post-outage costs and activities.[11] Subsequently, SCE and SDG&E have each filed applications for reasonableness review of 2012 recorded O&M and capital spending,[12] for approval of the totality of the SGRP costs,[13] and for power purchased during 2012, including replacement of power lost due to the outages.[14] The Utilities seek rate recovery from ratepayers for all of these expenses.

A prehearing conference (PHC) was held on January 12, 2013. The assigned Commissioner and Administrative Law Judge (ALJ) determined that to

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[11] OII at 8.

[12] A.13-01-016 (SCE), A.13-03-013 (SDG&E).

[13] A.13-03-005 (SCE), A.13-03-014 (SDG&E).

[14] A.13-04-001 (SCE).

promote the efficient administration of the OII, it would be divided into several phases, each with its own PHC and Scoping Memo. Among the benefits of this approach are: (i) the building of a chronological record, (ii) pacing for certain information not yet known, and (iii) consistent decisions in future phases.

On January 28, 2013 assigned Commissioner Michel Peter Florio and ALJ Melanie M. Darling[15] issued a scoping memo for Phase 1, set dates for parties to serve testimony, and established dates for evidentiary hearings in Phase 1. The Phase 1 scope is as follows:

1. Nature and effects of the steam generator failures in order to assess the reasonableness of SCE's consequential actions and expenditures;
2. Whether 2012 SONGS-related O&M expenses and capital expenditures recorded in the SONGSMA are reasonable and necessary, including:
    - 100% of cost-savings from personnel reductions and other avoided costs; and
    - 100% of refueling outage expenses;
3. A review of the reasonableness and effectiveness of SCE's 2012 actions and expenditures for community outreach and emergency preparedness related to the SONGS outages; and
4. Other issues as necessary to determine whether SCE should refund any rates preliminarily authorized in the 2012 GRC, in light of the changed facts and circumstances of the unit outages; if so, when should the refunds occur.

SCE's and SDG&E's applications for review of 2012 O&M costs and capital expenditures recorded in the SONGS Memorandum Accounts, consolidated with

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[15] On May 1, 2013, ALJ Kevin Dudney was co-assigned to the OII.

the OII, are the primary focus of review in Phase 1. These proceedings were consolidated with the OII in April, 2013.[16]

In response to the OII, SCE and SDG&E both argued the Commission lacked authority to (1) review and refund 2012 estimates of O&M and capital spending, as deferred by the GRC decision; and (2) remove any SONGS assets and associated O&M from rate base pursuant to § 455.5, prior to SCE's 2015 GRC. The Scoping Memo directed parties to brief these legal issues.

An April 30, 2013 Assigned Commissioner and Administrative Law Judge Ruling resolved these questions. As it relates to Phase 1, the Commission ruled that it has legal authority to conduct the deferred final reasonableness review of SONGS-related expenses (100%) sought in SCE's 2012 GRC and immediately order refunds, if warranted.[17]

Therefore, Phase 1 identifies what SONGS-related costs SCE and SDG&E incurred in 2012, and how should they be categorized, e.g., base (GRC) O&M, base capital expenditures, RFO base costs and emergent work, incremental and consequential steam generator inspection and repair costs. In addition, Phase 1 considers the reasonableness of the various identified 2012 costs given the facts and circumstances SCE knew, or should have known, at the time the costs were incurred. Finally, Phase 1 determines whether refunds should be issued to ratepayers for overcollections in 2012.

By e-mail ruling on May 3, 2013, the assigned ALJs created a sub-phase, called Phase 1A, to develop a method for calculating 2012 costs of replacement

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[16] Ruling dated April 19, 2013.

[17] Assigned Commissioner's and Administrative Law Judge's Ruling on Legal Questions (April 30, 2012) at 17.

power. Although the ALJs announced that they intended to resolve Phase 1A issues by a ruling, we have decided to resolve both Phase 1 and Phase 1A issues in today's decision.

Several parties participated in Phase 1 and Phase 1A by serving testimony, conducting cross-examination of witnesses, and/or filing post-hearing briefs. In addition to SCE and SDG&E, these parties are Division of Ratepayer Advocates (DRA),[18] The Utility Reform Network (TURN), Alliance for Nuclear Responsibility (A4NR), World Business Academy (WBA), Women's Energy Matters (WEM), Joint Parties (comprised of National Asian American Coalition, Ecumenical Center for Black Church Studies, Latino Business Chamber of Greater Los Angeles and Chinese American Institute for Empowerment), and the Coalition to Decommission San Onofre (CDSO).

Motions to alter the Scoping Memo, to immediately order refunds, strike testimony, etc. have been filed and ruled upon, none of which altered the course of the OII set forth in the Scoping Memo, except to clarify that ordinary review of power purchases by both Utilities would continue to occur in their respective Energy Resource Recovery Account (ERRA) proceedings.

Evidentiary hearings in Phase 1 were held from May 13 to 17, 2013. During examination of SCE witnesses, it was disclosed that SCE had identified "Base" O&M costs by timing each month, rather than by actual purpose of the expense. At the end of the hearings, SCE and SDG&E each agreed to provide an exhibit with a revised breakdown of 2012 costs by month, segregated as to Base O&M and costs incurred as a result of the outages. As a result, on July 22, 2013,

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[18] Now known as the Office of Ratepayer Advocates.

SCE served SCE-35 and SDG&E served SDGE-11. These exhibits are accepted into the proceeding record.

Phase 1 Opening Briefs and Reply Briefs were filed by SCE, SDG&E, DRA, TURN, A4NR, WBA, CDSO, Joint Parties and WEM on June 28, 2013 and July 9, 2013, respectively.

Evidentiary hearings in Phase 1A were held on August 5 and 6, 2013. SDG&E served late-filed exhibit SDGE-17 on August 9, 2013, which is an errata to SDG&E's 2012 SONGS Outage Memorandum Account (SONGSMA). This exhibit is admitted into the proceeding record.

Phase 1A Opening Briefs were filed on August 29, 2013 by SCE, SDG&E, DRA, and A4NR. Phase 1A Reply Briefs were filed by SCE, SDG&E, TURN, A4NR, DRA, and WEM.

The matter, including both Phase 1 and Phase 1A, is submitted as of September 12, 2013.

4. Standard of Review

Phase 1 is in essence a ratesetting action and the standard of review for rate recovery is the preponderance of evidence.[19] Despite A4NR's reference to dated Commission decisions which used the term "clear and convincing," this legal standard has been explicitly rejected by the Commission.[20] We are not persuaded by A4NR's argument that SCE's conduct has been found to be so imprudent in its response to the outages that the higher burden of proof should apply. The Commission has not made any finding of imprudence in the Phases

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[19] D.12-11-051.

[20] D.11-05-018 at 34.

resolved in this decision. Instead, the test is whether SCE's 2012 actions as the SONGS operator, were reasonable and prudent.

A4NR and SDG&E both emphasized past Commission findings which evaluated the reasonableness of operational decisions. As affirmed by SDG&E, SCE must show that its decision-making process was sound, its managers considered a range of options in light of information that SCE knew or should have known, and decided on an action within the bounds of reasonableness.[21]

A4NR recalls the Commission's prior finding that "a 'reasonable and prudent' act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction."[22]

This standard of reasonableness does not derive from the consequences of managerial action, but the soundness of the utility's decision-making process that led to the decision and the consequences.[23]

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[21] SDG&E Opening Brief (OB) at 3.

[22] A4NR OB at 7 (citing D.05-08-037 at 4-5).

[23] D.05-08-037 at 4-5 (citing D. 89-02-074) ("a decision may be found to be reasonable and prudent if the utility shows that its decision making process was sound, that its managers considered a range of possible options in light of information that was or should have been available to them, and that its managers decided on a course of action that fell within the bounds of reasonableness, even if it turns out not to have led to the best possible outcome").

5. Parties' General Positions

5.1. Utilities

SCE and SDG&E seek a finding that all of the 2012 SONGS-related recorded expenses are reasonable under the circumstances, and request Commission approval to recover 100% of the expenses in rates.

In addition to testimony provided in these proceedings, each utility has regularly provided the Commission with reports of recorded SONGS-related costs, pursuant to the OII.[24] As a result of accounting anomalies revealed, each utility provided a further breakdown of recorded "Routine" O&M between "Base-Routine" and "Base-SGIR" costs after the evidentiary hearings concluded.[25]

In 2012, SCE recorded its share of total "routine" O&M and capital costs of $520.2 million ($2012), plus an additional $139.8 million for the U2 RFO, seismic study costs, and SG Base and Inspection and Repair (SGIR) costs.[26] SCE recorded total (100% share) capital expenditures of $167.6 million, of which the SCE share is $131.08 million.[27] SGIR-related capital expenditures by SCE total $13.9 million.

SDG&E claims its total share of comparable 2012 costs is $133.47 million,[28] plus an additional $36.288 million for the U2 RFO, seismic study costs, and SGIR

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[24] SCE provides monthly reports, SDG&E provides quarterly reports.

[25] SCE-35; SDG&E-11.

[26] Appendix A, SCE Monthly Report filed in compliance with I.12-10-013 (February 1, 2013).

[27] SCE-04 at 87-88 (SCE recorded $133.606 million which includes $2.5 million for SCE's share of license renewal-related expenditures not claimed for recovery).

[28] Includes an adjustment of $694,000 based on difference between Routine O&M in 1Q2013 SDG&E Quarterly Report filed in compliance with I.12-10-013 (April 2, 2013) and SDG&E-11 ($73.559 - $72.865 million = <0.694 million>).

costs.[29] SDG&E recorded capital expenditures of $39.3 million invoiced by SCE, and an additional $10 million for its own overheads.[30] The capital expenditures for SGIR are not quantified.[31]

SCE contends that, in light of the nature of the steam generator failures, its consequential actions and expenditures during 2012 were reasonable, including completion of U2 refueling activities and all costs related to inspection and repair of the steam generators (SGIR). Although both SONGS units were in extended outages as a result of the tube problems in both units, SCE argues that SONGS was an operating facility in 2012.[32]

As operating agent, SCE states it was required to ensure that all plant systems remained functional to protect the nuclear fuel and to ensure the radiological health and safety of the public and workers. Systems were maintained, rather than be allowed to deteriorate, to prepare for resumed operations.

In addition, SCE claims it postponed or canceled some capital projects and O&M activity when it was possible "without compromising regulatory and safety-related objectives."[33] Furthermore, SCE asserts it would have been imprudent not to undertake actions to investigate the causes of the damage to the units, and to develop plans to return the units to service in the long-term.[34]

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[29] SDG&E-3 at 12; SDG&E-11 at 3.

[30] *Id.*, Work papers at 3.

[31] SDG&E-3 at 9; SDG&E 3-Workpapers at 3.

[32] SCE OB at 1.

[33] *Ibid.*

[34] *Ibid.*

Therefore, SCE asks the Commission to find that it acted reasonably in 2012 in taking actions to maintain systems, structures, components, and other processes and procedures as required by its operating licenses, and to restore the units safely to service. SCE also asks the Commission find that 100% of 2012 expenses recorded in the SONGSMA were reasonably incurred, and to allow full rate recovery.

SDG&E agrees with SCE, primarily because it relies on SCE to undertake decision-making and activities consistent with the terms of the Operating Agreement[35] and the NRC license.[36] SCE states that it "is unaware of any material facts or representation made by SCE during Phase 1 that would contradict SCE's written testimony or data responses pertaining to its consequential actions, the timing thereof, and the resulting expenditures in 2012 in light of the steam generator failures."[37]

SDG&E requests similar treatment for its share of total SONGS-related expenses recorded by SCE, and approval of approximately $60.5 million in other 2012 GRC costs for which the Commission deferred reasonableness review to this proceeding.[38] Although the extra SDG&E expenditures occur regardless of whether SONGS generates electricity, SDG&E claims they are required as a result of its ownership of SONGS. Therefore, SDG&E requests that these 2012

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[35] SCE and the other co-owners have executed an Operating Agreement covering the terms and conditions for operations and pro rata recovery of costs.

[36] SDG&E OB at 3.

[37] *Ibid.*

[38] D.13-05-010 (A.10-12-006).

incurred expenses associated with these activities be found reasonable, prudently incurred and recoverable from ratepayers

5.2. Division of Ratepayer Advocates (now known as Office of Ratepayer Advocates)

DRA disagrees that SCE has established any 2012 SONGS costs were reasonably incurred in 2012. Instead, DRA argues the Commission cannot conduct a reasonableness review of SCE's SONGS-related 2012 expenses, should not allow rate recovery at this time, and should promptly order refunds of "unnecessary" charges associated with SONGS.[39] DRA explains that "unnecessary" charges include revenue requirement collected in excess of actual expenses, but does not quantify what it considers "necessary" or "unnecessary."

DRA has "no objection" to eventual recovery of "verifiable" safety and security-related 2012 costs, but argues that SCE did not establish those actual expenses, e.g., no segregated safety expenses, no workpapers to support security expenses.[40] Moreover, DRA concludes there is insufficient evidence to support a Commission finding that SCE's 2012 actions and expenditures in connection with the steam generator failures were reasonable.[41] As to these costs, DRA recommends that the Commission defer any such finding until completion of the NRC's investigations into SONGS Units 2 and 3 and key facts about third party cost recovery are known.[42] One of DRA's witnesses went further and stated that no recovery should be allowed at all, because SCE can obtain recovery from MHI

[39] DRA OB at 12.

[40] *Id.* at 11.

[41] *Id.* at 6.

[42] *Id.* at 7.

or through insurance and it would prompt more shareholder oversight of management. [43]

5.3. The Utility Reform Network

TURN, similar to other non-utility parties, argued that "incremental" costs resulting from the steam generator failures should be removed from the SONGSMA and denied rate recovery here.[44] TURN asserts the incremental costs lack any presumption of reasonableness since they are "the direct result of imprudence by SCE and/or its vendors…."[45] Instead, TURN would remove all SGIR-related expenses from the SONGSMA and require a separate application for review.

TURN identified certain cost categories it agreed should be tracked in the SONGSMA (e.g., pre-core fuel inventory, materials and supplies inventory, cash working capital attributable to SONGS, third party payments), but found SCE's testimony "murky" and seeks further clarification for particular cost categories. TURN would limit utility rate recovery here to "unavoidable expenditures required to maintain the plant and meet minimum federal license requirements."[46] For example, "Base-Routine" O&M costs in the SONGSMA should be subject to reasonableness review, and TURN would cap recovery at the final levels identified by the utilities in Phase 1.[47]

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[43] TR at 992-993.

[44] TURN OB at 5.

[45] *Id.* at 7.

[46] *Id.* at 5.

[47] *Ibid.*

In addition, TURN recommends the Commission adopt a presumption that all Construction Work In Progress (CWIP) as of December 31, 2012 is abandoned plant, ineligible for accrued Allowance for Funds Used During Construction (AFUDC).[48] However, TURN suggests an exception for capital projects which SCE can show are necessary to maintain safety at the facility under permanent shutdown.

TURN also posits that the SONSGMA does not accurately capture all SONGS-related costs. TURN points to SCE's failure to provide a SONGS-only cash working capital (CWC) calculation, separate from its overall utility-wide CWC, including separate SONGS-only lead lag calculations, leading to an unacceptable omission of costs.[49]

TURN also asks the Commission to suspend SCE's authority to collect any future revenues for seismic studies related to the relicensing of the plant and eliminate any seismic O&M expenditures already incurred in Edison balancing accounts in current rates

5.4. Alliance for Nuclear Responsibility

A4NR rejects rate recovery for any 2012 SONGS-related expenses. As soon as SCE became aware of the extent of vibratory damage to the steam generator tubes in both units, A4NR argues that SCE should have decided to shut down permanently. A4NR concludes that SCE should have known the costs to repair or replace the steam generators, in light of about $1 billion of plant still in rate

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[48] *Id.* at 10.

[49] *Id.* at 14.

base, rendered any action other than immediate shutdown to be economically unreasonable.[50]

Based on SCE's proffered evidence of what it knew, or should have known, about the condition of the U2 and U3 steam generators in the immediate aftermath of the January 31, 2012 tube leak, A4NR asserts it is impossible to characterize the managerial decision making as sound, logical, reasonable, or prudent. A4NR also questions SCE's characterization of the most extensive types of wear in U2 as "manageable," an assumption that led to the U2 restart plan.

Furthermore, asserts A4NR, SCE's witnesses provided no evidence its managers considered a range of possible options in light of the information that was or should have been available to them. Because SCE failed to show why the decision to permanently shut down could not, and should not, have been made early in 2012, A4NR concludes that all subsequent facility-related rates are over-collections and should be refunded.[51]

5.5. World Business Academy

WBA assumes that sometime in 2012, SCE knew or should have known the SONGS facility would never restart or produce electricity again. Because SONGS is now permanently out of service, and has provided no power since January 2012, WBA urges the Commission to immediately refund 100% of 2012 SONGS costs retroactively to that date.[52] WBA contends SCE did not show that

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[50] A4NR OB at 2.

[51] *Ibid.*

[52] WBA-1 at 3.

its 2012 SONGS- related costs were just and reasonable, and delaying the return of revenues unjustly collected will continue to harm ratepayers.[53]

WBA claims SCE failed to meet its burden of proof because its testimony was largely conclusory, "offering broad narratives unsupported by the requisite degree of specificity and detailed explanation" (except for emergency preparedness).[54] Although WBA signals openness to rate recovery for costs and capital expenditures specifically related to ensuring safety of the plant, it found SCE's testimony "contradictory" and lacking in any uniform definition of "safety-related."

WBA focuses on SCE's claimed inability to segregate "safety-related" costs, and surmises SCE preferred to characterize all costs as safety-related in order to maximize recovery. As an alternative, WBA recommends the Commission order a third-party financial audit to identify all 2012 safety-related expenses for a final reasonableness determination.

Additionally, WBA contends that SCE and MHI are objectively at fault for the SONGS shut-down and third-party payments should cover consequential costs instead of ratepayers.[55] Finally, SCE did not demonstrate the reasonableness of its 2012 incremental costs to investigate the causes of the tube wear, develop a plan to return U2 to service at 70% power, and place U3 in an extended shutdown condition.[56]

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[53] WBA OB at 1.

[54] *Id.* at 3.

[55] WBA-1 at 5, 16.

[56] WBA OB at 10.

5.6. Women's Energy Matters

WEM opposes rate recovery for all 2012 SONGS-related costs, including the U2 RFO. WEM 's position is premised on the view that SCE knew the steam generators were "experimental" and knew or should have known they were irreparably damaged at the first inspection during the U2 RFO.[57] Instead of going to permanent shutdown, states WEM, SCE engaged in a futile and expensive set of activities to try to support the restart of U2. SCE's failure to undertake a cost-effectiveness analysis of the restart plan is further evidence of its unreasonable course of action, claims WEM.[58]

WEM argues that the only 2012 SONGS-related costs that might be reasonable to recover from ratepayers are those incurred in January, subject to refund if SCE is later found to have been imprudent or "committed fraud" regarding the SGRP.[59] Similar to TURN, WEM also contends some costs are missing from the SONGSMA because they are "buried" in other company budgets.

For example, WEM specifically identifies Community Outreach and Emergency Planning, Education, and Philanthropy[60] as one such area, along with Regulatory Affairs, and Information Technology support. WEM opposes all funding for Community Outreach activities which it views as functionally corporate public relations and designed to mislead, rather than educate, the

[57] WEM OB at 6.

[58] *Id.* at 11.

[59] *Id.* at 3.

[60] Utility philanthropy is not funded by ratepayers.

public.[61] WEM states it would only support cost recovery, if SCE expands emergency planning and public education beyond the minimum requirements of the NRC and Federal Emergency Management Agency.

5.7. Coalition to Decommission San Onofre

CDSO also favors immediate refunds of SONGS expenses collected in rates, and opposes ratepayer funding of any 2012 SONGS-related costs, except costs required to maintain safety-related components of the plant, as defined by the NRC.[62] Consequently, CDSO opposes rate recovery for any RFO and SGIR expenses.

CDSO asks the Commission to order SCE to identify the NRC-defined "systems, structures and components, and procedures and processes that are absolutely necessary in emergency, non-routine conditions to safely shutdown the plant and maintain it in a safe shutdown condition," and associated costs.[63] A public workshop run by the Energy Division is CDSO's suggested form of SONGSMA cost review.

Underlying CDSO's position is its allegation that SCE "deliberately misrepresented the SGRP to the NRC, the Commission, and the public, and knew the moment it discovered tube wear during the U2 RFO, that repairs were imprudent.[64] Furthermore, CDSO criticizes SCE for a failure to consider the

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[61] WEM-8 at 9.

[62] CDSO OB at 4.

[63] *Ibid.*

[64] CDSO OB at 5.

safety or costs of alternative solutions to the U2 restart. Instead, asserts CDSO, SCE should have moved both units to preservation mode in June.

Based on the Augmented Inspection Team (AIT) Report which identifies several "more than minor" procedure violations, CDSO claims ratepayers should not pay for (unspecified) non-compliant operations. The group also argues SCE's Community Outreach and Education costs are not reasonable because SCE does not comply with state law requiring a 35-mile radius for its public education zone.

5.8. Joint Parties

Joint Parties focused on Community Outreach and Education activities (in company-wide O&M), and criticize SCE for not taking "appropriate steps" to educate and inform a diverse population in the service territory surrounding SONGS.[65] One particular area of concern is that SCE does not specifically track the costs related to "SONGS outreach" which, according to Joint Parties, prevents the Commission and parties from fully evaluating SCE's actions and expenditures.[66]

Joint Parties specifically criticize some outreach activities, such as those conducted on weekdays when people with "regular jobs" cannot attend, or a Rotary Club presentation because it does not reach "the underserved.[67]" On a broader point, the group views many of SCE's outreach activities as primarily

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65 Joint Parties OB at 8.

66 *Id.* at 4.

67 *Id.* at 4-5.

about improving SCE's corporate image, instead of providing public education about SONGS.

Joint Parties asks the Commission to order SCE to provide an accounting for these costs and, that an employee be designated to coordinate all of the public education and community outreach efforts for SONGS.[68] The Commission should then defer its reasonableness review of these costs until the accounting is provided, and costs that benefit corporate image should be disallowed.

Other recommendations from Joint Parties are that SCE should be ordered to:

- expand the reach of its public education effort to be a 20-50 mile radius from SONGS;
- ensure that all community outreach, education, marketing, and external relations related to SONGS are, from this point forward, universally provided in Vietnamese, Korean, Khmer/Cambodian, Chinese, Tagalog, and Spanish; and
- conduct a comprehensive survey of communities within 20 miles of SONGS to ascertain residents' attitudes and knowledge regarding nuclear power and SONGS.[69]

6. What SCE Knew or Should Have Known

As a starting point for determining whether SCE's decision-making process was sound, the Commission examined the NRC's Confirmatory Action Letter (CAL)[70] and the NRC's AIT Report for the sequence of events and known facts, and an independent assessment of SCE's actions from NRC's on-site inspectors.

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[68] *Id.* at 5.

[69] *Id.* at 9-10.

[70] Appendix 2 to SCE-02 and SCE-03, Tabs 2, 25.

SCE provided a chronology of key operational facts and significant dates in 2012 related to the outages.[71] Based on the record, other dates and some information has been added to the timeline, which is attached as Appendix C. This chronology also assisted the Commission in its review of the reasonableness of SCE's actions and recorded expenses during 2012.

Both U2 and U3 were in their first cycle of operation with new replacement steam generators. Each replacement steam generator (SG) has 9,727 tubes, two SGs per Unit. In the straight-leg portion of the tubes, the tubes are supported by a series of tube support plates (TSP) through which the tubes penetrate. The U-bend region is located at the top of the tube bundle and is supported by an anti-vibration bar (AVB).[72]

According to SCE, and elsewhere in the record, SG tubes have historically experienced tube degradation related to various phenomena. These degradation mechanisms can impair tube integrity if they are not managed effectively. SCE states that when the degradation of the tube wall reaches a prescribed repair criterion, the tube is considered defective and corrective action must be taken.[73]

Based on the CAL, AIT Report, and SCE's testimony, we are persuaded by a preponderance of evidence that SCE knew or should have known the following:

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71 SCE-10 at Q4.

72 SCE-04 at 77-78.

73 *Id.* at 79.

- On January 31, 2012 when the U3 leak was discovered, U2 was about half-way through its scheduled refueling outage where significant inspections, testing, and repairs take place.[74]
- AIT found that SCE plant operators responded to the January 31, 2012, SG tube leak in accordance with procedures and in a manner that protected public health and safety. Plant safety systems also worked as expected during the event.[75]
- In early February, SCE's routine eddy current testing[76] of U2 tubes identified 2,411 tubes with indications (most less than 20%) of tube wear attributable to retainer bar wear, support plate wear, or AVB. SCE plugged six damaged tubes and another 182 tubes were plugged as a precaution.[77]
- AIT considered the U2 wear indications found similar to those found at other replacement steam generators after one cycle of operation.[78]
- On February 12, 2012, SCE inspection confirms leak in U3 SG tube; eddy current testing identifies unexpected retainer bar wear, similar to U2, and significant Tube-to-Tube wear (TTW) in the U-tube region of the SG.[79]

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[74] SONGS--NRC Augmented Inspection Team Report 05000361/20122007 and 05000362/20122007 (June 18, 2012) (AIT Report), § 1.1.

[75] *Id.* at Executive Summary.

[76] Eddy current testing involves inserting a probe into each tube and measuring the tube wall thickness throughout the full length of the tube through the use of electromagnetic signals.

[77] AIT Report at § 1.4.

[78] *Id.* at § 1.4 (A total of 2411 tubes were found with indications at the tube support plates and anti-vibration bar supports, the vast majority of which had a measured depth of less than 20 percent of the tube wall thickness).

[79] *Id.* at § 1.1

- On March 13, 2012, eight U3 tubes failed additional in-situ pressure testing by SCE's consultant (AREVA), of 129 tubes that showed the most wear.[80]
- AIT stated failure of U3 in-situ pressure test is an indication that, for certain design basis events, such as main steam line break, these SG tubes may not be able to maintain structural integrity.[81]
- On March 19-29, 2012, AIT was on-site conducting its inspections. MHI and SCE were onsite conducting cause evaluations for the tube failures and unexpected wear in U3.[82]
- On March 23, 2012, SCE submitted SG Return-to-Service (RTS) Action Plan to NRC outlining its commitments to corrective actions before restarting either unit.[83]
- On March 27, 2012, NRC sent SCE a CAL that notified SCE it may not restart either unit until SCE completes a list of actions and NRC completes its review of the actions, including:
  - ✓ Determine causes of TTW; plug all tubes with significant wear.
  - ✓ Submit written results of SG assessments for both units, proposed inspection protocols, schedule for a mid-cycle shutdown, and basis for SCE's conclusion thatU2 will safely operate as required by NRC regulations.
  - ✓ The CAL will remain in effect until the NRC has (1) reviewed SCE's response, including responses to staff questions and the results of SCE's evaluations, and (2) NRC has written its

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[80] U.S. Nuclear Regulatory Commission Confirmatory Action Letter to SCE (March 27, 2012) (CAL) at 1.

[81] *Ibid.*

[82] *Id.* at § 2.0.

[83] SCE-10 at Q4.

conclusion that the units can operate safely without undue risk to public health and safety, and the environment.[84]

- In March 2012, SCE developed a plan to postpone, cancel, and re-schedule capital projects; SCE also began work on short-term and long-term repair options.[85]
- On April 10, 2012, SCE identified two tubes with TTW in the U3 free-span U-bend region, where U2 TTW was found.[86]
- Regarding SCE's extensive U3 eddy current testing completed April 15, 2012, more than half of the TTW indications in each SG had maximum measured depths exceeding the 35% plugging limit in the technical specifications, and ranged to as much as 99%.[87]
  - ✓ Over 460 tubes in each SG had wear indications at the tube support plates; about 170 tubes in each SG exhibited indications at the tube support plates that exceeded the 35% plugging limit.[88]
  - ✓ Approximately 800 tubes in U3 SGs exhibited wear indications at the AVB supports; most measured less than 20%, only two exceeded the 35% plugging limit.[89]
  - ✓ Four tubes with retainer bar wear indications were plugged and stabilized; the remaining 184 tubes that intersect the retainer bars were plugged as a preventative measure.[90]

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[84] CAL at 2-3.

[85] TR at 714.

[86] AIT Report at § 1.4.

[87] AIT Report at § 1.5.

[88] *Ibid.*

[89] *Ibid.*

[90] *Ibid.*

- On April 23, 2012, SCE issued U2 tube wear Root Cause Analysis (RCA) which identified the cause of TTW as Fluid Elastic Instability (FEI).[91]
- On April 26, 2012, SCE Board of Directors was told that U2 RTS was scheduled for 6/1, and U3 on 6/30, after SCE responded to the CAL.[92]
- On May 7, 2012, SCE issued U3 RCA which included identification of TTW in U2 and U3.[93]
- In March/April and May/June, SCE was able to fully characterize the conditions at U2 and U3, respectively, and focus on responding to TTW.[94]
- On June 18, 2012, the NRC held a public meeting and presented the AIT Report to SCE executives who acknowledged the findings, including:
  - ✓ NRC team identified ten "unresolved" items requiring additional review for regulatory action.
  - ✓ SCE was adequately pursuing the causes of the unexpected TTW degradation; SCE retained a significant number of outside industry experts, consultants, and SG manufacturers to perform modeling and analysis.
  - ✓ SCE was adequately pursuing the causes of the unexpected steam generator tube-to-tube degradation. SCE retained a significant number of outside industry experts, consultants, and steam generator manufacturers, including Westinghouse

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[91] SCE-04 at 82.

[92] A4NR-5 at 2.

[93] SCE-10 at Q4.

[94] TR at 772.

and AREVA to perform thermal -hydraulic and flow induced vibration modeling and analysis.[95]

- In June 2012, SCE began planning to put U3 into Preservation Mode.[96]
- On June 12, 2012 MHI issued its technical RCA.
- On June 18, 2012, NRC presented AIT Report Exit at public meeting.
- In July 2012, SCE created a long term repair team for both units to develop options with MHI.
- On October 3, 2012, SCE submitted Response to CAL; NRC identifies 6 -7 month window for review, inspections, response to staff information requests, public meetings, etc.
- On November 11. 2012, NRC issued draft Report of vendor inspection at MHI: two notices of non-conformance re Quality Assurance issues.
- On December 5, 2012, the Atomic Safety Licensing Safety Board held hearing to determine whether SCE will need a license amendment to try U2 restart plan.
- On December 14, 2012, MHI sends two progress letters to SCE regarding development of long-term repair options.[97]
- December 20, 2012, MHI provides long-term repair options and recommendations.[98]

6.1. Discussion

This discussion draws inferences as to what SCE knew in 2012 based on the facts as they unfolded and became known to SCE. The non-utility parties

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[95] AIT Report at § 14.

[96] SCE-10 at Q4.

[97] SCE-16, SCE-17.

[98] SCE-15.

argue from the assumption that SCE entered 2012 with pre-existing knowledge about risks and problems with the design and/or operations of the replacement steam generators arising from the inception of the project in 2004. However, the SGRP was approved by the Commission in 2005, rate recovery authorized upon completion, and a presumption of reasonableness applied if costs remained below forecasts.

Therefore, in this phase, we confine our review to knowledge gained by SCE in 2012 which informed, or should have informed, SCE's decisions in how to respond to the SG problems. In Phase 3, we will examine the SGRP as a whole and, if it is established that SCE had pre-existing knowledge about risks at the SGs, then it is possible that some or all SGIR-related expenses in 2012 may be found unreasonable.

During January and February, the Commission finds that SCE acted as a prudent operator of a generation facility to detect the U3 leak, identify the source of the leak, inspect all of the U2 and U3 tubes for damage, investigate the causes of excessive and unexpected wear, and to assess whether repair is a reasonable option. SCE first knew about both excessive wear in both units and the unique phenomena of TTW in U3 in mid-March. This raised the question of whether there was a design, installation, or operation problem, and whether it was fixable, and if SCE bore any fault. SCE considered TTW as the most significant and complex phenomena, and a key barrier to restart of U2.[99]

SCE understood that the units were likely to be offline for some time, because SCE developed a plan in March to postpone, cancel, and re-schedule

[99] TR at 735.

capital projects and began work on short-term and long-term repair options. SCE also notified the NRC in March of its decision to restart U2, before understanding the causes of TTW, whether it existed in U2, or what repair options were viable. The NRC responded by prohibiting either unit from restart until SCE received written permission from the NRC.

By April, SCE was able to fully characterize the conditions at U2 and focus on responding to TTW, as the other wear was "manageable."[100] SCE understood from its own RCA issued in April, that the cause of the unprecedented TTW wear was a previously unknown condition: Fluid Elastic Instability (FEI). However, at least by May 7, when SCE confirmed by its own analysis that both units had TTW, SCE knew the fix for FEI was not going to be quick. The U2 RTS date continued to slip.

Nonetheless, SCE states it had high confidence U2 would restart in 2012, and decided to maintain readiness to operate, despite costs that amounted to about $1 million per day.[101] The assumption was "an important assumption in terms of how we prioritize work for the plant staff, the operators, and others".[102] At an April 26 meeting of the Board of Directors, SCE managers unrealistically advised the Board that U2 could return to service by June 1, and U3 by June 30.[103] These projections were unrealistic for several reasons.

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100 TR at 772.

101 TR at 947; A4NR OB at 23-24.

102 TR at 947.

103 A4NR-5

TTW was new and unique, and SCE had retained several expert consultants to assist SCE and MHI with analyzing the problem and providing possible restart options. Any repair options would take time to develop and implement. Moreover, the NRC had prohibited SCE from any restart until NRC certified SCE had complied with the many conditions of the March CAL. SCE implies that compliance with the CAL is pro forma and immediate. This is incorrect and SCE, an experienced operator, should have known better. As evidenced by how the NRC responded to SCE's eventual CAL response, submitted in October, there would likely be a six to eight month process lag until the NRC could issue written permission to start—assuming no license amendment was required (by no means assured).

During the first few months of 2012, SCE worked closely with the NRC, MHI, and its contracted experts Westinghouse, AREVA, and Intertek to investigate the damage and to develop operational assessments to support a limited restart of U2 for the purpose of testing impact on the SG tubes. SCE had near daily meetings with them and knew, or should have known, the general thinking and direction of the forthcoming AIT report and MHI RCA.

On May 7, SCE knew, or should have known, by its own analysis that U2 was susceptible to the same TTW, and could no longer be run at 100% power which provided the damaging steam flow. After months working with SCE on-site, MHI issued its RCA and AIT issued its Report in June, both of which reached conclusions about the presence and source of TTW consistent with SCE's own prior analysis. The AIT Report found that both the U2 and U3 SGs were susceptible to the design-induced TTW:

> "…the NRC team concluded that both units' steam generators were of similar design with similar thermal hydraulic conditions and

configurations. **Therefore, SONGS Unit 2 steam generators are also susceptible to this phenomenon (emphasis added).**"

Notwithstanding the potential for TTW, SCE teams worked with MHI and expert consultants to develop both a U2 restart plan, and long-term repair options for both units. SCE's restart plan was to operate U2 at 70% for five months then go offline to gather data about tube wear.

SCE contends the decision to restart U2 was part of normal operations for an operating generation facility--simply a delayed restart from a scheduled outage. It was more than that. SCE was prohibited under its license from restart of either unit, until it had completed a months-long response to the CAL, and the NRC had several more months to process the response. Yet, SCE did not consider other options, or consider that it had failed to accurately estimate the time necessary to obtain NRC approval. Instead, it was singularly focused on the restart option on the grounds that it "obviously" was the best option. As a consequence, SCE decided to retain the staff required for a fully operational facility, resulting in large O&M expenses even as some employees voluntarily left in September and later.

A decision-making process which does not consider alternative actions, cost effectiveness, or the ratepayer's perspective is not reasonable or prudent.

It is undisputed that the tube wear in U3 was more extensive than in U2 but the units have similar tube designs. In June, SCE began planning to put U3 into preservation mode, and the SCE Budget Review Committee met to defer capital projects. At that time, SCE knew U3 would not restart in the foreseeable future, and should have known that U2 was similarly situated.

U2 would not restart in 2012, in part because SCE was months away from submitting its CAL response, and six or more months away from NRC approval, assuming no license amendment would be required for the 70% test. This pushed the U2 restart date into at least 2Q 2013, but was not acted upon in contrast to SCE's actions regarding U3. For example, during a September Board of Directors meeting, SCE managers justified its move of U3 into preservation mode based on SCE's revised 4Q2013 estimate for U3 RTS.

The Commission finds the primary purpose of SCE's U2 restart plan was not for electric generation; it was a theoretical test for five months at 70% power, to gather data for long-term repair options. Therefore, it does not qualify as "normal operations" but as a strategic step towards long-term RTS in late 2013.

SCE did not establish that its decision to keep all systems operating instead of putting Unit 2 into preservation mode was reasonable. SCE acknowledged it would take just two months to move U3 from preservation mode to service-ready. Given the built-in time delays facing development and approval of SCE's restart plan, it is not reasonable to assume that U2 would restart in 2012, which might have justified retention of the employees. Instead, it was possible to decide that U2 could be handled similarly, even though SCE admitted it did not consider it. It may be that SCE's decision was reasonable when viewed in light of the lay-up and RTS costs, a consideration we will make during the entire SGRP review in Phase 3. However, we cannot find it reasonable in 2012 because it was ill-considered, based on the Phase 1 record.

Therefore, based on confirmation that U3 had tube-to-tube wear, the Commission finds that SCE knew or should have known by March 15 that a potential design defect was present in both units and thus fault could become an issue to rate recovery. Therefore, incremental SGIR costs would likely be disputed, and not suitable for immediate rate recovery until the Commission could develop a record about them.

The Commission also finds, based on confirmation that both units had tube-to-tube wear in the same area, that SCE knew or should have known by May 7, 2012 that pursuit of a restart plan for U2 was not in the interests of immediately restoring power generation for the benefit of ratepayers. Instead it was a brief theoretical exercise to further the development of long-term repair options with MHI.

The Commission concludes the record does not establish that costs associated with the restart and long-term repair options (SGIR) are routine O&M for which it would be just and reasonable to collect immediate recovery from ratepayers.

7. 2012 Recorded Expenses in SONGS Outage Memorandum Accounts

For 2012, SCE and SDG&E reported year-end recorded expenses to the Commission for their respective SONGSMA accounts, as follows (excluding power replacement and U2 RFO costs (discussed elsewhere in the decision):

2012 YE Recorded SONGS-related Non-capital Expenses ($000s)

Subaccount	SCE	SDG&E
Base -Routine O&M	300,489	72,685
Seismic Safety	3,261	832
Investigation	67,059	17,155
Repairs – After Outage	27,302	6,004
Regulatory – After Outage	3,421	903
Defueling	932	167
Litigation	6,145	--
Payroll Taxes	13,442	3,744
Other (Pensions, PBOP, Insurance)	23,059	31,624
Unit 2 Refueling Outage (RFO)	**35,255**	**9,116**
Total	**443,536**	**133,294**

8. Base O&M and Other Non-Capital Costs

In each utility's GRC, the O&M/overhead forecasts were based on normal operations at SONGS in 2012. However, SCE incurred routine operating expenses, as well as incremental other costs resulting from the outages of both U2 and U3 (SGIR). SCE and SDG&E also recorded other non-capital costs related to the U2 RFO and Commission-ordered seismic studies. (Capital expenditures are discussed below.)

8.1. Operations and Maintenance (O&M) Costs

In today's decision, we segregate recorded O&M costs into two categories: Base O&M and Steam Generator Inspection and Repair (SGIR) O&M. In the context of a GRC, Base O&M costs are primarily for labor and associated overhead costs. SCE submitted testimony which addressed SONGS total (100%) O&M by SONGS Functional Group.[104] SCE's testimony provided a description of the type of activities undertaken by each functional group, including some systems or activities SCE states are required by its operating license and associated technical specifications, to remain safely operable and capable of performing their design. Over the course of the proceeding, SCE eventually divided O&M into three categories: Base-Routine, Base-SGIR, and SGIR.

A summary of the type of activities and systems by functional group, preliminarily allowed (GRC) Base O&M costs, recorded costs, and an estimate of the percentage of costs necessary to comply with regulatory requirements as put forth by SCE is attached as Appendix D.

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[104] SCE-04.

SCE also provided a final 2012 O&M Summary by functional group which separates slightly revised costs by Base-Routine and SGIR-related costs.[105] Of the total $488,702 million recorded (100% $2012) for O&M costs, $347.747 million is recorded as Base-Routine, $140.955 million as SGIR-related (including Base-SGIR). This total amount is approximately $100 million more than the $389 million preliminarily allowed for all O&M in the GRC decision. In addition to Base and SGIR O&M, SCE also reports O&M costs related to information technology (IT), employee severance, and an artificial functional group for accounting purposes called Corporate Support. These costs are $9.054, $17.600, -$20.463 million, respectively. The negative value for Corporate Support reflects its use as a credit.

SDG&E 's O&M costs are not wholly derivative from its 20% ownership interest, because it applies separate overheads and calculates its own capital costs. For 2012, SDG&E reported total O&M as follows: $106.122 million for Base-Routine (+ overhead) and $26.34 million for SGIR-related.

8.2. Discussion of Base O&M and SGIR O&M

Typically, the Commission reviews forecasted costs in a GRC based on previous spending history and proposed new activities. The utility re-allocates the total revenue requirement adopted by the Commission based on emerging priorities. SCE contends that it did just that in 2012 with preliminarily allowed revenue --which SCE re-directed to inspections, testing, developing the U2 restart plan and long-term repair plans, and putting U3 into preservation mode.

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105 SCE-35 at 6.

In this review, based on recorded costs, the Utilities' position is that all non-capital costs recorded in 2012 should be considered reasonable because as a prudent operator, SCE had a duty to identify the problems in the units, protect the assets for potential return-to-service, develop repair and return-to-service (RTS) plans, and to maintain safe operations and conditions at SONGS in compliance with regulatory requirements and SCE's NRC license and associated technical specifications.[106] Therefore, SCE and SDG&E assert the Commission should not order any refunds.

The Utilities rely on cost-of-service ratemaking principles where ratepayers are expected to pay for the reasonable costs of the generated electricity received, and utilities have an opportunity to earn a regulated rate of return over the estimated life of an asset. The Utilities reject the positions of WEM, CDSO, and WBA which advocate disallowance of all costs during these outages as a result of no electricity being generated. SCE argues it fundamentally undermines the risk sharing principles implicit in cost-of-service ratemaking, and further observes that ratepayers benefit when assets outlive expected service lives (e.g., hydroelectric plants).

The Commission agrees that cost-of-service ratemaking is applicable to regulated electric utilities, and automatic disallowance of all costs whenever there is an unplanned outage is erroneous. We expect that generation facilities like SONGS will have some planned and unplanned outages during ordinary operations. However, not all outages are the same, and indeed these extended outages resulting in premature, permanent shutdown are unique, particularly

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[106] SCE-2 at 27.

after nearly a billion dollar investment, with generators in their first cycles of operation. The Commission has oversight responsibility to carefully examine an electric utility's actions to ensure that amounts charged to ratepayers are just and reasonable.[107]

All of the non-utility parties view SCE's testimony and other evidence as insufficient to establish what O&M costs SCE incurred and whether the costs were reasonable. There is some agreement that it may be reasonable for ratepayers to pay for "safety-related" costs, but no party accepted SCE's expressions of judgment as to the percentage of functional group expenses. DRA points out the offered percentages lack work papers or other supporting documentation.[108]

We have reviewed SCE's testimony and found the narrative descriptions similar to what is provided in a GRC, and consistent with the type of activities known to occur at SONGS. Although this review is based on actual costs, we agree with SCE that a sufficient showing does not require an itemized list of all O&M costs. Based on the Commission's knowledge gained through decades of regulatory oversight, we are able to find that SCE generally provided adequate explanations of what O&M activities it undertook and why, albeit without specific detail for Base O&M. (For the much more limited SGIR costs, SCE provided an itemized breakdown of costs.) In response to any residual concerns, we observe that SCE's books and records will be examined by ORA as part of its upcoming GRC, and the Commission always retains jurisdiction to audit.

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[107] Pub. Util. Code § 451.

[108] DRA-02 at 2.

For most Functional Groups, the recorded Base-Routine O&M is less than the GRC amounts, due in part to re-allocations of expenses to SGIR. One substantial example is the Engineering Group where SCE recorded more than $110 million to Engineering SGIR (discussed below).[109] Security costs also rose, but only about 5%., or $2.2 million, and are not unexpected.

Excluding Severance costs (discussed below), 49% of Base O&M costs are recorded in either the Maintenance or Nuclear Support Groups. SCE recorded $88.154 as Maintenance Base-Routine O&M, about $20 million less than the GRC amount.[110] SCE claims this is because it took steps to limit overtime and reduce contractor work force from about 200 to 65 full time equivalents, enhanced work processes, and rescheduled some non-critical maintenance activities.[111]

According to SCE, the Maintenance Group supports the actual plant electrical systems by "performing preventive and corrective maintenance and regular surveillance testing of mechanical and electrical equipment, instrumentation and controls, and protective devices" in compliance with various regulatory requirements, industry standards, and internal controls.[112]

The group reportedly processed 15,795 work orders during 2012, fewer than 4,000 were for U3. This low number is understandable given that (1) during April-May, SCE evaluated all scheduled preventive maintenance and surveillance testing resulting in suspension of 700 U3 work orders and re-

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[109] SCE-35 at 6.

[110] *Ibid.*

[111] SCE-33.

[112] SCE-04 at 27.

scheduling 300 surveillance tests; and (2) in June SCE began planning to put U3 into preservation mode.[113]

The Nuclear Support Functional Group provides administrative support to SONGS O&M, including Business and Financial Services, Site Support Services, Nuclear Business Administration, and General Expenses. Activities include financial planning, budgeting, and accounting policies, preparation for ratemaking proceedings, record management, employee timekeeping, payroll, regulatory compliance programs, environmental protection programs, and payment of required fees.[114]

For the Nuclear Support Group, SCE recorded $82.5 million in Base-Routine O&M, about $7 million (8%) less than the GRC amount. SCE argues that regardless of whether SONGS is producing electricity, many of the identified functions of this group had to be carried out, particularly as it relates to the presence of employees, financial planning, and compliance with document-related regulatory compliance.

We observe that the activities described for both groups are generally of the type necessary to provide routine administrative services and to keep all systems operating, including critical systems necessary to keep the plant in a safe condition compliant with its operating license. That is to say – Base O&M. Similarly, we find that the activities described for the other Functional Groups are appropriate and predictable activities at an operating nuclear facility.

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[113] *Id*. at 28

[114] SCE-04 at 61-63.

Based on the historic O&M costs provided,[115] we find that the total recorded Base-Routine O&M is similar in proportion by Functional Group, and about 10.5% less in total amounts recorded, to what we would expect of an operating facility – the status the Utilities impute to SONGS.

However, we disagree that SONGS should be considered an "operating facility" for all of 2012. First, neither unit produced electricity for ratepayers after January 31, 2012. Second, by mid-March when it confirmed U3 TTW, SCE knew that there was a probability that issues of design fault would arise and SGIR expenses should be segregated for separate review. By May7, 2012, after confirming TTW and other types of tube wear in U2, SCE knew or should have known that it was not reasonably foreseeable that Unit 2 would return to producing electricity in 2012 or even that a short-term restart was viable.

Therefore, the Commission concludes it is reasonable for SCE to recover total recorded O&M, including Base-Routine and all SGIR (discussed in more detail below) for January, February, and half of March when all activities involved the reasonable response of a prudent operator to an unexplained outage. Beginning in the second half of March, all SGIR expenses, including Base-SGIR, are not yet eligible for rate recovery and shall be segregated for further review in Phase 3, subject to refund, where issues of outage-related fault or imprudence by SCE will be raised.

Additionally, SCE's Base-Routine O&M is reasonable through May. However, we find that SCE's request to recover all Base-Routine O&M recorded in 2012 is unreasonable. The record is not sufficiently detailed for the

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[115] SCE-29 at Tab 8.

Commission to try to reconstruct what portion of post-May Base O&M is not reasonably associated with the minimum activities which would have been incurred if SCE had not pursued its decision to restart U2, and both units moved into preservation mode. We do know that SCE recorded normal time costs for SCE employees for SGIR activities as normal time funded via the base budgeting process. Therefore, commission finds recorded Base-Routine O&M is excessive after May.

Several parties criticize SCE's showing, and it is true that the Commission is not in a position to find that every O&M cost was properly recorded as "Base-Routine" O&M instead of SGIR. Nonetheless, such granular review is atypical for a GRC, and we note that in Phase 3 we will be examining SGIR activities more closely. Therefore, the Commission finds that ratepayers will be best served by proceeding with the record at hand to adjust rates with reasonable approximation.

In order to account for Base-Routine O&M costs incurred as a result of SCE's not well-considered decisions to maintain all, or nearly all, operating staff through the end of 2012, we conclude a gradually increasing reduction to Base-Routine O&M should occur, beginning in June. The Commission finds it reasonable and in the public interest to adopt a sliding path of decreasing Base-Routine O&M between June and December of 2012 to reflect both the unreasonable decision to devote all resources to a U2 restart in 2012, unrecorded credits, and various uncertainties about what was recorded in Base O&M.

Beginning in June, 10% of Base-Routine O&M shall be disallowed, followed by 20% in July and so on until November and December 2012 when

40% of Base-Routine O&M will remain in rates.[116] This amount approximately conforms with SCE's unsupported estimate that about one-third of SCE's Base-Routine O&M is necessary to maintain safe conditions and full regulatory compliance in a permanent shutdown mode. The result is reasonable because shutdown is a viable possibility for SCE after December 20, when MHI presents two repair options: SCE questions the viability of one strategy on a technical basis, and the other is full or partial replacement of the SGs, over a multi-year period.

The Commission finds reasonable and adopts the following 2012 Base-Routine O&M for SONGS-related costs, as follows (in 000s of 2012$, 100% share):

	Base - Routine	SGIR (includes both "Base" and "Total" SGIR)	Total
Recorded	347,746	140,956	488,702
Authorized	273,867	18,353	292,220
To Review in Phase 3	---	122,603	122,603

A worksheet for these calculations is attached as Appendix E.

8.3. Steam Generator Inspection and Repair (SGIR) Costs

SCE recorded $140.956 million (2012$, 100%) for 2012 incremental SGIR expenses, including $8.555 million re-allocated post-hearing from Base O&M.[117] Above, we found that $8.555 million recorded as SGIR through March 15, 2012

[116] In Phase 2 of these proceedings, the Commission is considering whether to remove plant from rate base, along with associated O&M, as of November 1, 2012.

[117] SCE-35 at 6.

was reasonable for ordinary operations during an unplanned outage. SDG&E's post-hearing adjustments identified $26.34 million recorded for incremental SGIR.[118] In support of these claimed amounts, SCE submitted testimony by Functional Group, as described above, including some descriptions of SGIR activities. SCE also provided an itemized breakdown by unit, work order, and Functional Group.[119]

SCE recorded about $113 million of SGIR costs in the Engineering Functional Group, more than 80% of total SGIR costs recorded in 2012. A majority of the costs ($94.6 million) was for outside consultants, experts, and contractors for testing, analysis, and tube plugging in both units.[120]

According to SCE, the Engineering group works in conjunction with Maintenance to perform day-to-day repairs of SONGS systems that remain in service. SCE also points to several regulatory-driven safety-related programs which SCE asserts must continue even during shutdown conditions.[121]

More specifically, the Engineering group consists of five functions: (1) Design Engineering; (2) Plant Engineering; (3) Nuclear Fuel Management; (4) Nuclear Safety Concerns; and (5) Nuclear Oversight and Assessment.[122] SGIR-Engineering costs are significant, states SCE, because the staff was fully engaged in plant restart activities (e.g., analyzing cause of tube wear in the SGs, defining and managing lay-up activities, determining repair options, supporting

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[118] SDGE-11 at 2.

[119] SCE-10 at 13 – 21.

[120] SCE-04 at 85-86.

[121] *Id.*at 35.

[122] *Id.* at 30.

regulatory review and requests for information, and maintaining the units available for restart).[123] This evidence is undisputed and, as described, corresponds to known emergent work otherwise documented in the record.

Some Engineering Expense was labor, "necessary to maintain qualified staff to perform functions required by the SONGS operating licenses and technical specifications."[124] No one challenged SCE's testimony that hiring and retaining qualified engineers is difficult, which made short-term staffing adjustments of engineers "cost-prohibitive and not the industry standard."[125]

The next largest recorded amount for SGIR was $7.4 million for the RadChemical Control Function (RadChem) Group, including $4 million for contractor health physics technicians and laundry services for radiologically controlled areas.[126] According to SCE, the Health Physics division establishes, implements, and manages the radiation protection and radioactive material control programs for SONGS, as well as interfaces with state and federal agencies responsible for radiological health and safety.[127] Its Chemistry division manages various chemistry control programs, manages the radioactive effluent monitoring program, and provides technical support.

During 2012, the Utilities argue that all of these activities are necessary to maintain SONGS in a safe and secure condition during extended outages, and to restore the units safely to service. The Chemistry division was particularly active

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123 *Id.* at 36.

124 *Ibid.*

125 *Ibid.*

126 SCE-04 at 86.

127 *Id.* at 41.

in ensuring that U2's systems could be returned to service safely, and U3's systems were adequately protected for longer-term shut-down. Notably, SCE admits the total O&M (Base and SGIR) for this group would have declined overall if it had decided in 2012 to move for permanent shutdown.[128]

None of the non-utility parties support the Utilities' request for rate recovery of SGIR expenses in 2012. Instead, the parties outright reject all recovery because the facility was in extended shutdown, should have been permanently closed in 2012, costs should be paid by insurance and MHI, or SCE was at fault and its shareholders should cover the costs.

We give these arguments for automatic disallowance for all SGIR-related costs no weight because the record does not support them. We have made no finding that SCE was at fault or imprudently managed the steam generator replacement project, or unreasonably incurred the incremental SGIR costs in 2012. However, the prudence of SCE's management of the project, and whether costs associated with the replacement steam generators were reasonable and necessary, will form the basis for the third phase of these consolidated proceedings.

As we discussed in relation to Base O&M, an unplanned outage does not necessarily mean that a utility was at fault or that it should be assumed to be a permanent condition for purposes of rates. Moreover, SCE has agreed to apply any warranty or damage amounts from MHI, and insurance recovery, to offset SGIR costs for the benefit of ratepayers. SCE acknowledged it received a payment from MHI for $45.5 million (100%) and it should be applied towards

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[128] *Id.* at 44.

SGIR costs as determined in Phase 3. However, we decline to speculate as to future third party recovery and prematurely apply credits before funds are in hand.

Our review of the (100%) costs allocated to SGIR is incomplete. Based on the itemized SGIR costs initially provided by SCE, the Commission makes an initial finding that the items and activities referenced appear to be of the sort that could be undertaken to investigate, inspect, and repair steam generators, develop and implement a restart plan, and move a reactor unit into preservation mode.

However, we have not yet determined whether these costs are reasonable under the circumstances and, therefore, whether ratepayers should pay for any of them. In Phase 3, we will examine the 2012 incremental costs in context of the overall SGRP and SCE's management of the project, and apply third party payments received from MHI or insurance.

Above we concluded SCE was reasonably pursuing normal operations, or a return thereto, through May 2012. During June through December, we made reductions to recorded Base O&M given SCE's decision to restart and maintain full operations at SONGS throughout 2012. The result is that the removed Base O&M is re-allocated to SGIR for final review in Phase 3.

Therefore, the total 2012 SGIR expenses, subject to further review in Phase 3 is $122,603 million.

8.4. Severance Pay

In its 2012 GRC, SCE forecast preliminary workforce reductions of 500 SONGS personnel, and 100 contractors, to align the workforce with those of the other nuclear generating sites over time.[129] The Commission found the proposed reductions had been delayed since 2009, resulting in ratepayers funding excess positions for two years to rectify management problems at SONGS which required a resetting of the safety culture through various activities. We determined that SCE should allocate to ratepayers 100% of savings from reductions of SONGS personnel.[130]

Based on the changed conditions and 2012 staffing needs, SCE revised planned reductions to 730 over 2012-2013, reducing staff by almost one-third, from 2,250 to 1,500.[131] SCE reports voluntary severance of 258 employees and involuntary severance of 15 managers, in November and December of 2012. The actual severance costs were $17.6 million, with savings of $3.96 million.[132]

The GRC O&M amounts included all estimated severance costs within Functional Groups.[133] In SCE's report on recorded O&M, severance costs are a presented as a separate item, and not available by Functional Group. SCE stated the delayed reductions were a result of re-allocation of staffing to meet new inspection and repair activities, the need to retain highly skilled employees for anticipated outage and restart-related tasks, and the lengthy process to layoff represented employees, e.g. collective bargaining, bumping rights.[134]

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[129] SCE-1 at 2.

[130] D.12-11-051 at 33; (TR at 1211 SCE witness Mr. Worden stated that the GRC model had not made that adjustment, but SCE would abide by it if adopted here).

[131] SCE-04 at 36.

[132] *Ibid.*

[133] TR at 369.

[134] TR at 1089-90.

Although employee severance costs are routine costs, the Commission finds it was not reasonable for SCE to retain full staffing through November of 2012. The Commission also finds that SCE has not credited the $3.96 million in 2012 savings from staff reductions to the overall calculation of costs. In order for rates to be just and reasonable, we conclude that this credit must be made to the overall costs subject to rate recovery for 2012 Base O&M. We address both issues as a part of the gradual O&M reductions adopted above.

8.5. Seismic Studies

In D.12-05-004, we approved SCE's and SDG&E's applications to record and recover their actual costs of up to $64 million (nominal $, 100% share) in O&M costs associated with seismic studies at SONGS. These studies are responsive to Public Resources Code Section 25303 and recommendations of the California Energy Commission.[135] In testimony, TURN suggests that these seismic study costs are related to relicensing and should be disallowed,[136] but does not advance this argument in briefs. In testimony and briefs, SCE suggests that TURN misunderstands the purpose of the seismic studies and asserts that the studies are a regulatory obligation, not related to license renewal.[137]

SCE's recorded costs for seismic studies in 2012 are $3.261 million; SDG&E's are $815.5 thousand.[138]

We find that these studies were authorized by this Commission and are not directly related to the operational status or relicensing of SONGS.

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135 D.12-05-004 at 1-2.

136 TURN-1 at 9.

137 SCE OB at 24-25, citing SCE-8 at 9.

138 SCE February 1, 2013 Monthly Report in Compliance with I.12-10-013; SDGE-11 at 2.

D.12-05-004 describes certain ratemaking treatment for these studies. Based on the record in this proceeding, we do not make any changes to the previously approved ratemaking treatment of these studies.

9. 2012 Capital Expenditures

SCE initially planned to undertake substantial capital projects at SONGS during this rate cycle. In the 2012 GRC decision, the Commission preliminarily authorized SCE to expend $189.2 million ($2012, 100%) for anticipated operational needs.[139] SCE actually recorded $167.6 million (100%) in total capital expenditures. Unlike O&M expenses, SCE's testimony combines U2 RFO capital expenditures and SGIR expenditures with all other SONGS-related capital expenditures.

9.1. Utility Applications

SCE asks the Commission to find that its 2012 SONGS-related capital expenditures of $131.08 million (SCE share) are reasonable, along with other capital costs recorded in SONGSMA. SDG&E requested approval for $49.3 million in capital expenses, comprised of $39.25 million identified as its 20% share of SONGS capital expenditures billed by SCE, adjusted for overheads ($1.19 million), plus $8.82 million for AFUDC.[140] (It is unexplained whether the AFUDC is actually attached to plant into rate base during 2012.) SDG&E's testimony also addresses its capital-related revenue requirement—a different calculation and rate component.

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[139] SCE-04 at 88.

[140] SDG&E-3 at 9; See Appendix B (SDG&E's reports capital expenditures of $38.475 million in its SONGSMA).

According to SCE, Units 2 and 3 required on-going capital investment in 2012 to maintain the plant's condition at a level supporting long-term safe, regulatory-compliant, and reliable operation – both in the near-term during shut-down conditions and in the long-term when and if either or both return to service. SCE provided cost and descriptive information about the capital projects (most presented earlier in the 2012 GRC), and took steps to postpone, suspend, or cancel some projects during 2012 based on the extended outages, including projects related to the suspended U3 refueling outage.

SCE contends that recorded capital expenditures are $21.6 million less than preliminarily allowed, largely due to the outages. Implementation of SCE's plan to postpone, cancel or re-schedule capital projects during 2012, claims SCE, also led to savings. Therefore, SCE asserts that all expenditures should be found reasonable.

SCE points out that 47% of the capital expenditures were incurred prior to April 2012 (with the majority of that amount incurred during the Unit 2 Cycle 17 RFO), before the full extent of the wear conditions of the Unit 2 & 3 steam generators was known. SDG&E supports SCE's position that over 80% of the 2012 capital expenditures were necessary to maintain the units in a safe and secure condition, or to meet federal and state regulatory requirements.

SDG&E provided a table of adjustments to SCE invoices for its pro rata share of capital expenditures. SCE provided a narrative description of capital projects SCE states it was unable to defer, such as the U2 RFO, as well as those it could postpone or suspend without compromising safety. SCE classifies the capital projects under the following sub-categories:

Capital Expenditures By Category[141]
($2012, $millions)

Category	Projects	100%	SCE	SDG&E
Common Required includes capital projects for site, not unit specific, but necessary;	more than $23 million is required for storage of spent fuel	38.389	30.024	7.678
Work In Progress Projects in progress in 2011, mostly completed, required to sustain plant infrastructure	Completion prudent given mostly complete; includes back-up generators; almost 90% is related to U2 RFO;	84.533	66.113	16.907
Emergent-Regulatory Required not forecast, due to new regulatory requirements	74% for various security projects; $2.6 million for	17.937	14.029	3.587
Rescheduled Projects begun in 2012 & suspended due to outages	Small U2 and U3 projects	1.434	1.122	0.287
On-going Completion Rescheduled Projects started before 2012 suspended due to outages	Primarily for U3 RFO, $9 million for high pressure turbine	19.754	15.450	3.951
Marine Mitigation Requirement of Coastal Commission permit	$4.2 million for corrective construction to wetlands project; monitoring of artificial reef	5.559	4.350	1.112
Total (includes RFO)		$167.61	$131.088	$33.522

DRA and WBA argue that the Commission should not find any SONGS-related capital expenditures to be reasonable. DRA contends the Utilities did not provide sufficient information to establish reasonable capital

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141 *Id.* at 89-113; Appendices A and B to this Decision (Year End 2012 SONGSMA report).

expenditures in 2012. Both DRA and WBA ask the Commission to further defer review of these expenditures.[142] However, we find deferral unnecessary because there is sufficient evidence to make an approximate determination of reasonable capital expenditures during 2012.

We agree with the Utilities that some capital expenditures were necessary during 2012, even though the reactor units were not operating, because the NRC operating license requires SCE to maintain many systems in order to protect the safety of the plant, its workers and the public

Our review of the pattern of expenditures confirms that more than $89 million (53.5%) of total capital expenditures were booked between January and April 2012, primarily for the U2 RFO. We conclude below that the RFO was essentially completed before SCE had knowledge of the extent and nature of tube wear in U2, and allow O&M associated with the RFO as reasonable. Similarly, we find that SCE's capital expenditures for the U2 RFO were reasonable when made, although we do not concur that SCE established the U2 RFO expenditures are necessary for maintaining a safe plant during the outage.

On the other hand, we found elsewhere in this decision that SCE knew or should have known by May 7, 2012 that it was not reasonable to expect either unit to return to service for up to a year. Therefore, we find that SCE 's effort to suspend, cancel, and re-schedule some projects, while commendable, was inadequate to reflect the overall reduction of capital projects that should have occurred at SONGS.

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[142] DRA OB at 12.

It is appropriate to reduce the amount of 2012 SONGS capital expenditures the Commission finds reasonable by 20% to reflect what the Utilities' internal experts determined were not necessary to safely maintain SONGS during the 2012 outage, in compliance with applicable federal and state regulations.

Therefore, the Commission finds that only $134.08 million (80%) of 2012 total recorded capital expenditures ($167.6 million) are reasonable. Capital expenditures will be subject to further review in Phase 3 if the expenditures were made as a result of the tube damage in the U2 and U3 SGs.

9.2. Capital-related Expenses Derived From Rate Base

When capital projects are completed, the capital expenditures are recorded into rate base as in-service and capital-related expenses (e.g., depreciation, taxes, return) are charged to ratepayers. According to SCE's SONGSMA report, the capital related-expenses increased substantially beginning in March and more than half of the total revenue requirement for these expenses was added between March and May 2012.

Although SCE provided assumed closing dates for its 2012 capital expenditures, SCE did not identify which capital expenditures and projects were actually moved into rate base during 2012. In the SONGSMA, SCE reported its net rate base (additions and removals) grew by $78.66 million from January 30, 2012 through December 31, 2012.

Additionally, 2012 combined capital-related revenue requirements exceed preliminary allowed amounts for both utilities. For example, SCE recorded depreciation expenses of $80.3 million, or $20.3 million more than the GRC amount.143 Tax expense also exceeds the GRC amount by $18.4 million. SDG&E similarly asks that its capital –related revenue requirement be found reasonable, but did not support its request for recovery of $27.3 million, $3.1 million more than its GRC estimate.

TURN and DRA are the only parties to directly address capital-related expense. DRA argues that utility recovery of SONGS Units 2 and 3 rate base related revenue requirements, along with SGRP revenue requirements, should be terminated effective January 31, 2012, the date of the Unit 3 forced outage. The SGRP revenue requirement is not at issue in this phase. However, we agree that not all capital investment moved into rate base was reasonable, as evidenced by excess capital-related expenses charged to ratepayers, and the net increase to rate base over the year.

However, DRA's recommendation to remove all SONGS assets from rate base is too blunt because it does not consider that capital work at U2 was part of a scheduled outage, that SCE did not know as of January 31, 2012 that U2 and U3 were not likely to return to service in 2012, or thereafter what capital was reasonable and necessary to maintain safe and secure conditions at SONGS in compliance with federal and state regulations.

TURN's position is that, as of November 1, 2012, the capital-related costs of U3 should be removed from rates based on the principle that fixed costs should be removed from base rates if there is no near-term timetable for a unit to come back. The single largest capital cost is the return, taxes, depreciation, and property tax for U3 (excluding common plant), which has about $110 million of

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[143] SCE SONGSMA Report (February 1, 2013 at 3).

rate base (return plus income taxes) plus property taxes in the range of $14.5 million annually, and depreciation expense of approximately $25 million. TURN's position is based on § 455.5 which will be addressed by the Commission in Phase 2.

The Commission finds that SCE's recorded rate base is excessive and should be reduced to reflect the changed conditions at the plant as the year progressed. The reduction should reflect removal of capital projects added to rate base in 2012 that do not compromise the safe operation of the plant in compliance with all regulatory requirements during the year. Therefore, it is reasonable to apply the 20% reduction adopted for capital expenditures to serve as a reasonable proxy for excess capital projects moved to rate base in 2012. This amount shall be removed from the rate base and any associated revenue requirement found to be unreasonable for 2012.144

There is no need for SCE to attempt, post-decision, to try to parse its capital projects in a different way. This decision only affects 2012 revenue requirement. Evidentiary hearings in Phase 2 have already been held where the Commission will address all SONGS plant in rate base and associated O&M pursuant to § 455.5. Furthermore, all costs related to the SGRP and subsequent outages remain under review in Phase 3 where issues of fault could lead to further rate reductions.

TURN also proposed that 50% of the Materials & Supplies (M&S) inventory be removed from rate base. However, SCE opposes the adjustment on

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[144] Due to tax consequences, the reduction in rate base actually results in an increase to revenue requirement of $0.5 million; larger reductions to rate base would result in a higher revenue requirement.

two grounds: (1) it was reasonable to maintain M&S inventory in 2012; and (2) TURN assumes an erroneous premise that M&S is apportioned 50/50 by unit. TURN's assumption is incorrect, and fails to recognize that some M&S is for common plant.

TURN's position is predicated on a finding that U3 should be removed from rate base in Phase 1 because it is abandoned plant. The Commission has not made that finding and the Phase 1 record does not support that result. We also observe that it would result in nominal increase to revenue requirement.

No other specific testimony or argument was made by a party about these elements of revenue requirement. As described above, the Commission previously authorized rate recovery of SGRP costs until the post-completion reasonableness review occurs. We view TURN's requests to reduce rate base as relevant to the Commission review of rate base pursuant to § 455.5 in Phase 2.

9.3. Construction Work in Progress

During 2012 a number of capital projects at SONGS were delayed or suspended. By the end of the year, SCE recorded $216.7 million (SCE share) for Construction Work in Progress (CWIP).[145] CWIP costs are not in rate base. This amount reflects projects where money has been spent but the project was not yet in-service at the end of 2012. Allowance for Funds Used During Construction (AFUDC) represents the cost of financing capital projects before they enter service. It is accumulated while the projects are under construction, and then included with the capital cost of the project when added to rate base.

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145 Appendix A.

The associated AFUDC accrued by SCE for these capital projects totaled $14.5 million.[146] SDG&E reports that, at as of December 31, 2012, it had recorded $110.855 million in CWIP, but did not identify accrued AFUDC.[147]

TURN initially recommended the Commission order SCE to stop accruing AFUDC on suspended capital projects, retroactive to the date of suspension.[148] As a result of SCE's 2013 decision to permanently shut down the entire facility, TURN urged the Commission to presume all recorded CWIP represents abandoned plant as of December 31, 2012, ineligible for the accrual of AFUDC. The requested result would be that the Utilities zero out all accrued AFUDC.[149]

TURN primarily relied on accounting standards to support its view. TURN cites Statement of Financial Accounting Standards (SFAS) No. 34 which requires the capitalization of interest to cease when a construction project is suspended voluntarily by the company. Federal Energy Regulatory Commission (FERC) requirements are apparently similar as applied to suspended construction of gas pipelines.

SCE and SDG&E adamantly opposed TURN's recommendations. They object that, if adopted, the Commission would be improperly preventing the utilities from recovering the 2012 cost of financing SONGS capital projects, regardless of future events.[150] During 2012, it was not clear whether U2 or U3

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[146] TURN OB at 9-10.

[147] Appendix B.

[148] TURN-1 at 10.

[149] TURN OB at 3-4.

[150] SCE-8 at 10.

would return to service, but the capital expenditures had received preliminary approval.

SCE also argues that the referenced accounting standards are neither determinative, nor applicable. We agree with SCE that the Commission's judgment on whether costs are reasonable is not controlled by accounting standards. The utilities distinguished the accounting rules cited by TURN. TURN did not refute SCE's claim that SFAS-71, not SFAS-34, is the applicable accounting rule for public utilities, and provides for accrual of financing costs with capitalized costs.[151]

We also disagree with TURN's premise that since the June 2013 announcement that SONGS will not restart, it is reasonable to assume the plant will be removed from rate base, the CWIP will never be placed into rate base, and there is" no possibility that these capital projects will be deemed used and useful."

This phase is primarily an extension of the 2012 GRC, converted from a forecasting exercise to review of what was reasonable given what SCE knew at the time it incurred the expenses. The Utilities state that, in 2012, SCE did not suspend substantially all activities at SONGS, and some necessary capital work continues.

We agree it is not reasonable to impute knowledge of a June 2013 decision to shut down SONGS permanently, to SCE during 2012. Furthermore, TURN jumps to the conclusion that no 2012 capital projects could be reasonable, an assumption that seems imprudent given that some critical systems may be

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151 SCE-8 at 10; SDG&E-5 at2.

impacted and capital investment required to meet regulatory obligations regardless of the operating status of the plant in 2012. Thus, some projects recorded in CWIP may have entered service in 2012, or will enter service in the future.

TURN suggested an exception to its blanket disallowance of all CWIP for capital projects which SCE can show are necessary to maintain safety at the facility under permanent shutdown.[152] However, this neither addresses the fact there is no evidence to show that SCE knew in 2012 that it would permanently shut down SONGS in 2013, nor that projects to maintain safety adequately describes the universe of reasonable capital projects left at SONGS.

Therefore, the Commission does not find it reasonable to prevent the Utilities from accruing AFUDC in 2012 for SONGS-related CWIP. However, the issue is relevant in phase 2 where the Commission may remove some SONGS plant from rate base, and associated projects may become permanently abandoned.

9.4. Cash Working Capital

SCE did not calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012. CWC is a component of rate base which represents the shareholder cost of funding day-to-day operational requirements when there is a gap between the time expenses must be paid and corresponding revenues must be collected. The Operational Cash requirement is the average balance of funds SCE's investors provide the utility to meet its daily operational needs.

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[152] TURN OB at 3.

In SCE's 2012 GRC, SCE provided a "lead lag" study to determine the required funds, based on estimated timing differences between when certain operating expenses are paid and revenues are received.[153] The Commission adopted SCE's Revenue Lead lag study, but made several adjustments advocated by DRA and TURN to SCE's proposed Expense Lag Study.[154] To the extent the Commission decides to make changes to revenue requirements in this proceeding, there will be some minor consequential effects to CWC.

TURN initially called for a SONG-specific lead lag study to support a SONGS-only CWC calculation, claiming that some SONGS costs would otherwise be omitted from review. At the evidentiary hearings, TURN's witness acknowledged that such a study could require significant extra work, and agreed that use of the company-wide lead lag study to SONGS expenditures would still be useful.[155]

In its post-hearing brief, TURN clarified that it wanted the Commission to order SCE to calculate a SONGS-only cash working capital (CWC) calculation, separate from its overall utility-wide CWC, using the parameters adopted in the 2012 GRC.[156] SCE disputes this approach, because the total company-wide Expense lag does not necessarily reflect the Expense Lag associated with SONGS.[157]

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153 D.12-11-051 at 633-34.

154 D.12-11-051 at 640-645.

155 TR 795-896.

156 TURN OB at 4.

157 SCE OB at 45; SCE-8 at 3.

We agree with TURN's intent to capture all 2012 SONGS-related costs for review in this Phase. SCE stated in its post-hearing brief that if it were directed to perform the calculation, it could develop an approximate estimate using the lead-lag days adopted in the GRC. Although not a perfect measure, the Commission finds it reasonable to direct SCE to perform the calculation, as it proposed, which may result in a minor, but reasonably appropriate, adjustment to SONGS rate base. SCE shall provide the Commission with this calculation as part of the revised modeling of the revenue requirement which SCE shall undertake as a result of this decision.

10. SDG&E Other SONGS-Related Costs

SDG&E incurred $60.492 million of SONGS-related costs not included in the SONGS portion of SCE's 2012 GRC or in SCE's OII testimony.[158] These cost categories and forecast amounts were addressed in SDG&E's 2012 GRC and include capital-related expenses arising from the SGRP.

SDG&E's SONGS-Related Costs Deferred from GRC
($YOE 000s)

Category	Amount
SONGS Unit 1 Spent Fuel Storage	994
SONGS Site Easement	20
SONGS Insurance	2,364
SONGS Operations and Billing Oversight	642
SONGS Depreciation	23,273
SONGS Taxes	13,270
SONGS Return on Rate Base	19,929
Total	$60,492

[158] SDG&E-3 at 2.

SDG&E provided testimony which described the nature of these expenses, although somehow omitted any reference to the SGRP. The categories Depreciation, Taxes, and Return on rate base include a total of $29.1 million related to the SGRP. We expect this omission was an oversight and not intended to shield this component from review SDG&E argues that all of these costs are required regardless of whether SONGS is operating and have been deemed reasonable in prior rate cases. SDG&E requests the Commission find the expenses reasonable and prudent.

We recognize that, under a prior decision, the Utilities currently have authority to recover these costs. However, SDG&E is aware the decision also provided for a final reasonableness review of the SGRP costs, which will occur in Phase 3 of these proceedings. Therefore, our interim finding that these costs are reasonable does not exempt these SGRP costs from the final review to come.

With that caveat, the Commission finds these 2012 costs to be reasonable and authorizes rate recovery.

11. Community Outreach and Education

At the request of Joint Parties and others, the Commission included in Phase 1, a review of SCE's 2012 actions and expenditures for community outreach and emergency preparedness related to the SONGS outages. The costs of SCE's Customer Outreach and Emergency preparedness programs are part of the company-wide GRC review, primarily through budgets for Local Public Affairs and Corporate Communications. SCE 's community outreach program is implemented in three public zones: a 10-mile radius from SONGS is the

Emergency Planning Zone, a 20-mile radius is the public education zone, and 30-50 miles is the "ingestion pathway" zone.[159]

SCE points out that the requirements for emergency preparedness followed by SCE, and other operators of commercial nuclear plants in the United States, are established by the NRC, Federal Emergency Management Agency (FEMA), and certain state agencies. SCE described its emergency preparedness activities on an on-going basis, and illustrated what it called "a significant community presence in the region surrounding SONGS."

For example, SCE performs regular drills and exercises site-wide and in coordination with the Interjurisdictional Planning Committee (IPC). In 2012, SCE reports it also provided radiological training for area Emergency Responders and updated service agreements with several area hospitals and transportation services.

After the outages, SCE states it also stepped up its public education program within the 20-mile plant radius, including numerous outreach presentations to local communities and school districts, sent Emergency preparedness brochures to 60,000 ratepayers within the federally-established 10-mile Emergency preparedness Zone, and expanded availability of Spanish language materials within the 20-mile public education zone.

Both Joint Parties and WEM ask the Commission to order SCE to segregate SONGS-related public education activities from SCE's company-wide program and subject these costs to future review. Both parties contend that SCE's efforts are insufficient, and include significant corporate image activities of questionable

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[159] "Ingestion pathway" refers to the potential for radiation to contaminate food sources.

value to the ratepayers. WEM criticizes the content of SCE's materials as "pro-nuclear public relations." WEM suggests a broad range of potential consequences of radiological leaks and emergency instructions should be required, and more extensive outreach beyond regulatory requirements. Joint Parties want the Commission to order SCE to appoint a single person to coordinate SONGS-related outreach and emergency preparedness and to translate all materials into numerous languages.

SCE observes that WEM does not dispute that SCE remains in full compliance with state and federal regulatory requirements, nor does WEM argue that SCE has failed to comply with any federal, state, or county regulations regarding emergency preparedness. No party contradicted SCE's assertion that, to the extent WEM objected to certain statements in its materials, the statements are accurate and consistent with similar information disseminated by federal and state authorities responsible for emergency preparedness in the event of a nuclear power plant accident.

SCE also provided evidence that, in 2011, the NRC reaffirmed its commitment to the 10-mile radius requirement for Emergency Planning Zones (EPZ) around U.S. nuclear power plants. The NRC said, "The current EPZ size has been in use since the 1970s and was the result of extensive emergency planning studies performed by a federal task force. That task force concluded a 10-mile-radius EPZ would assure that 'prompt and effective actions can be taken to protect the public in the event of an accident' at a plant."

SDG&E adds that the Commission has already rejected Joint Parties' proposal in the SDG&E 2012 GRC. In D.13-05-010, the Commission said, "to impose a SONGS-related community outreach program on SDG&E would be duplicative of what SCE already does, and would result in unnecessary programs whose costs would be borne by ratepayers."

We are not persuaded that SCE's SONGS-related outreach fails to meet regulatory requirements or misleads the public. The Emergency Planning zones are established by the federal government, and there is insufficient evidence in the record for the Commission to intervene in the multi-jurisidictional emergency planning in place. Although some community outreach activities listed by SCE may have a self-serving component in terms of corporate image, we have previously supported an IOU's involvement with communities within its service territory.

On the other hand, we agree with the thrust of parties' concerns that, going forward, communities surrounding SONGS will begin to learn more about the coming decommissioning and have new questions and concerns. Therefore, the Commission finds it is in the public interest for SCE to expand its public education about SONGS and the future decommissioning beyond the 20-mile designated public education zone to 50 miles for the immediate future. SCE shall be particularly sensitive to pockets of alternative language users and coordinate with community based organizations to ensure wide distribution of public information and availability of emergency planning information.

Therefore, within 90 days of the effective date of the decision, SCE shall make an Information-only Filing, as defined in Section 3.9 of the General Rules of General Order 96-B, to the Commission which identifies SCE's strategy for expanding its public outreach activities as described.

12. Refueling Outage (RFO)

In SCE's 2012 GRC A.10-11-015, the company requested approval for two refueling outages (RFO) in 2012, one for SONGS Unit 2 during January –March

2012 and one for Unit 3 during October – December 2012, at a cost of $46 million (100%) each, or $36 million (SCE share). SCE submitted that it began the first RFO in January 2012 on U2. However, in the decision for SCE's 2012 GRC D.12-11-051, the Commission noted that U2 was not restarted and directed SCE to track the RFO expenses in the SONGSMA for future reasonableness review.[160] Based on the operational uncertainty of the SONGS units, the Commission continued the flexible outage schedule mechanism for the GRC cycle, but did not allow preliminary recovery of SCE's estimate of $72 million (SCE share) for the two forecast RFOs in 2012.[161]

12.1. Parties' Positions

SCE notes that based on its 2011 expectations, "the company included expenses for two RFOs – totaling $102.606 million – in rates." However, since D.12-11-051 did not authorize any 2012 revenue requirement for RFOs, SCE has "overcollected" by that amount. SCE explains that, "through the routine operation of SCE's Base Revenue Requirement Balancing Account (BRRBA)" the difference will be refunded to ratepayers, through SCE's 2013 ERRA forecast proceeding.[162]

During January – March 2012, SCE conducted one RFO, the U2 Cycle 17 RFO, at a cost of $45.1 million; the U3 Cycle 17 RFO was not conducted.[163] SCE's testimony describes the activities of the U2 Cycle 17 RFO.[164] SCE asserts that

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[160] D.12-11-051 at 34.

[161] *Ibid.*

[162] SCE Phase 1 OB at 46-47, citing SCE0-7 at.6.

[163] SCE Phase 1 OB at 46, citing SCE-4 at 76.

[164] See SCE-4 at 69-76.

these activities were "incurred before SCE was aware of the extent of the tube wear in either unit" and that the Commission should, in this proceeding, find the costs reasonable and authorize SCE to recover them in rates.[165] SCE summarizes this ratemaking in its testimony:

> In other words, SCE will refund the previously-collected forecasted costs of the Unit 2 and Unit 3 Cycle 17 RFOs when the recorded 2012 BRRBA balance is included in rates, and is seeking to recover the recorded costs for that Unit 2 Cycle 17 RFO costs in future rates.[166]

SDG&E notes that its 20% share of RFO costs were invoiced by SCE and paid by SDG&E. SDG&E asserts that these costs are reasonable and should be recovered in rates.[167] SDG&E further explains that it included $28.7 million in 2012 rates for two RFOs (via Advice Letter 2302-E), and that it has already (via Advice Letter 2416-E) refunded, in 2013 rates, the amount not spent on the 2012 RFO.[168] SDG&E does not clarify in testimony the amount it recorded for the U2 Cycle 17 RFO. In combination SDG&E's Quarterly Reports on its SONGS Outage Memorandum Account dated June 10, 2013 and July 1, 2013[169] show a recorded cost of $9.1 million for the 2012 RFO.

DRA "recommends that the Commission direct SCE to refund any RFO revenues recovered in rates that are in excess of the RFO expenses incurred in 2012 and incorporate the adjustment in rates immediately."[170]. DRA's calculation

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165 SCE OB at 47.

166 SCE-7 at 7.

167 SDG&E Phase 1 OB at 4.

168 SDGE-6 at 1-3.

169 Line 29: "Refueling {1 in 2012}."

170 DRA Phase 1 OB at 15.

of the over-collection is that \$102.6 million was authorized for two RFOs in 2012,[171] and the actual costs of the U2 Cycle 17 RFO were \$45.1 million,[172] yielding a difference of \$57.5 million to be refunded.[173]

TURN suggests that SCE made an unreasonable decision to place new fuel in the U2 core during the RFO and the consequence "was an unnecessary destruction in value that could have been recouped through a resale of the unused fuel."[174] TURN asserts that SCE-4[175] demonstrates that by "early February of 2012" SCE had "substantial evidence of problems" at U2 prior to moving the fuel to the core, completed on March 1.[176] TURN-1 shows that SCE transferred \$121 million to the in-core inventory in June 2012.[177] TURN suggests that the Commission can calculate lost value "either by relying on an independent assessment or by using pricing data when SCE ultimately sells its existing unused pre-core fuel inventory."[178] CDSO also argues that moving fuel to the U2 core was unreasonable.[179] CDSO observes that SCE witness Palmisano estimates a typical timeframe for moving fuel to the core is seven days.[180] SCE

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171 DRA-1 at 10.

172 SCE-4 at 76.

173 DRA Phase 1 OB at 15.

174 TURN Phase 1 OB at 10.

175 At 77.

176 TURN Phase 1 OB at 10, citing timeline in SCE-10, Question 4 at 1.

177 TURN-1 at 3.

178 TURN Phase 1 OB at 11.

179 CDSO Phase 1 OB at 4.

180 *Id.* at 5, citing RT 764:16-18.

concurs with this observation, and places the start date at approximately February 25.[181]

SCE contends that TURN and CDSO's claims "assume perfect foresight regarding the nature and extent of the Unit 3 steam generator failure, which was not understood until a later point in time."[182] SCE's Palmisano interpreted the U2 testing, as of February, 2012, to show "overall satisfactory results."[183] Because contractors were already on site, SCE further argues, delaying insertion of the fuel as scheduled would have imprudently resulted in additional costs.[184]

WEM, A4NR, and Joint Parties do not directly comment on the subject of RFO costs.

12.2. Discussion

No party contests that exactly one RFO occurred in 2012, and no party has challenged the amount recorded by the utilities for the U2 Cycle 17 RFO. We agree with DRA's recommendation that any over-collection for a second 2012 RFO originally forecast for U3 should be refunded, to the extent that that refund has not already occurred. We find that SCE's cost of $45.1 million (100% share) for the 2012 U2 Cycle 17 RFO were reasonably incurred and authorize each utility to recover their share of these costs in rates. Any amount previously collected beyond this amount, including any collection for the U3 Cycle 17 RFO that did not occur, shall be refunded to ratepayers, to the extent that such a refund has not previously occurred.

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181 SCE Phase 1 Reply Brief (RB) at 3.

182 SCE Phase 1 RB at 3.

183 RT 850:11-14.

184 SCE Phase 1 Reply Brief at 3, citing RT 766:13-24.

Despite arguments by TURN and CDSO we find that SCE's decision to place new fuel in the U2 core was reasonable. Before SCE initiated the fuel insertion on February 25, 2012, SCE did not have sufficient evidence to delay placing fuel in the reactor of U2. Although SCE knew of the U3 steam generator leak and of unexpected levels of tube-retainer bar wear in both U2 RSGs, it did not yet know of TTW in one of the U2 RSGs. SCE testimony, cited by TURN,[185] does reference TTW, but TURN mistakenly attributes this conclusion to the U2 "expanded" eddy current testing completed on February 14, 2012. The correct date of this finding is April 10, 2012,[186] which apparently corresponds to the "special interest" eddy current testing started on April 5, 2012.[187]

13. 2012 Replacement Power Cost Calculation (Phase 1A)

The purpose of Phase 1A of this proceeding is to adopt a method for calculating the approximate[188] cost of replacement energy and capacity, foregone sales, and other market related costs (collectively "replacement power costs") of the outage of SONGS. If, in a later phase (tentatively Phase 3) of this proceeding the Commission determines a certain range of dates that SCE and SDG&E should not be allowed to recover the replacement power costs, this method will be

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185 SCE-4 at 77 and SCE-10, Question 4 at 1.

186 RT 852:21-25.

187 SCE-10, Question 4 at 1.

188 We cannot calculate the precise replacement power costs because market participants, including the utilities, would have made different bidding, procurement, and operational decisions if the outage had not occurred. Consequently, it is impossible to know with certainty the outcome of those decisions or the market prices that would have resulted. See SCE-2 at 19. No party suggests that it is possible to calculate replacement power costs exactly.

applied to calculate replacement power costs for those dates. As scoped, Phase 1A is limited to calendar year 2012. However, if circumstances require, we will investigate what, if any, differences in the method should be used for other time periods. We reiterate that the costs referenced here are only for meeting the needs of bundled customers; this discussion is separate from ongoing discussions in the long term procurement plan proceeding, Rulemaking 12-03-014, about system reliability in light of the SONGS outage and retirement. Here we focus exclusively on the cost of what has been done to meet the needs of bundled customers in 2012, not what may (or should) be done in the future on behalf of system customers.

13.1. Definition of Replacement Power

Some of the parties have devoted considerable energy to the debate of what categories of costs should actually be encompassed by the method to be established here. SCE suggests that replacement power costs should be "limited to the costs SCE incurred to replace lost SONGS generation for hours in which SCE had a net-short energy position."[189] SDG&E concurs.[190]

TURN instead suggests that the definition include "*all* the economic harm – in the form of higher revenue requirements and rates – that the SONGS outages would otherwise impose on bundled customers."[191] A4NR supports the TURN recommendation. DRA argues that several different capacity-related and

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[189] SCE Phase 1A OB at 5.

[190] SDGE Phase 1A Reply Brief at 3.

[191] TURN Phase 1A OB at 1.

market-related costs should be included because they are "financial consequences" of the outages.[192]

SCE observes that, since California's electric industry restructuring in 1998, utility-owned generation exists in a market-based framework and suggests that our Phase 3 discussion of replacement power cost recovery should be informed by this reality.[193] We agree that the replacement power cost calculations should be based on the realities of the market at the time of the outage.

Our intended, high-level, definition of replacement power costs is the net increase in costs to the utility of meeting its energy and capacity obligations to bundled customers. More specifically, this definition:

- Includes the cost to replace lost, potential generation as well as lost revenues from potential sales. SCE's argument that foregone sales should not be considered has no merit. As proposed by the utilities in this proceeding, the only distinction between a MWh of energy to be replaced and a MWh whose sale is foregone is the utility's position at the relevant hour. The change in net cost to meet customer energy needs due to the lost MWh is only impacted by price at that hour. We do not see a reason to draw any distinction on cost responsibility (as opposed to cost calculation) based on the utility's position.
- Includes capacity and demand response costs allocated to bundled customers for maintaining system reliability in Southern California, to the extent these costs are clearly linked to the SONGS outage. SCE argues that capacity-related charges should not be considered replacement power because they do not "replace the energy output of SONGS."[194] SCE does not provide an affirmative rationale for why non-energy replacement costs

[192] DRA Phase 1A Reply Brief at 3.

[193] SCE-37 at 1-2, SCE Phase 1A OB at 3-4.

[194] SCE Phase 1A OB at 12.

should be treated differently than replacement energy costs. DRA observes that SCE's own testimony contradicts SCE's brief, quoting SCE-8 "These 2012 CAISO charges can be considered replacement costs because they were incurred as a result of power charges assessed to SCE to replace generation from SONGS."[195]

- Includes onsite SONGS loads. SCE argues that replacing onsite loads is not replacement power because SONGS is not a "bundled customer."[196] TURN points out that this "is a distinction without a difference."[197] We find that load from the SONGS facility is not qualitatively different than load from bundled customers, it is simply load that would have been met by SONGS generation had SONGS been generating energy. The cost of meeting this load with non-SONGS energy is a replacement power cost.

- Does not include changes in the value of pre-existing utility hedges, including Congestion Revenue Rights (CRRs), but does include the net cost (e.g. cost net of revenues received) of CRRs purchased in response to the outages. We have a history of encouraging and requiring the utilities to hedge their risks against adverse outcomes. The SONGS outage is one example of the type of adverse outcomes that the utilities should hedge against. In order to avoid creating a perverse incentive against hedging, we will not consider changes in the value of the utilities' portfolio of hedges as replacement power costs. This does not preclude our evaluation of any new hedges in later phases of this or other proceedings.

- Does not include Energy Efficiency (EE) programs. WEM suggests that "surplus" achievements of EE programs saved more energy in 2012 than forecast and that this should be

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195 DRA Phase 1A Reply Brief at 2-3, quoting SCE 8 at 15-16. Note that DRA's reply brief incorrectly attributes the quote to an earlier portion of SCE-8.

196 SCE Phase 1A OB at 13.

197 TURN Phase 1A Reply Brief at 11.

> considered in calculating replacement power costs.[198] As SCE observes, "there is no evidence that SCE incurred additional EE costs in 2012 in connection with the outages."[199] We agree. To the extent that EE programs led to loads being lower than forecasted, this may have changed the utilities' net positions (i.e. they were less short or longer than they would have been). Potentially, this could have shifted costs from replacement energy to foregone sales, resulting in a change to net costs. However, the record before us presents no viable means of quantifying this inaccuracy or correcting for it.

For clarity, we divide our discussion of the replacement power method into three categories. Each of these categories would be calculated individually, and then summed together to reach a total replacement power cost for the identified range of dates. The categories are:

1. Replacement energy costs and foregone energy sales,
2. Capacity-related costs, and
3. Other market related costs.

To prepare for using this method in a future phase, we direct each utility to serve exhibits detailing their calculation of replacement power costs according to the method here.

13.2. Replacement Energy Costs and Foregone Energy Sales

The replacement energy and foregone energy sales category represents the net cost to the utility of meeting its bundled energy needs that would have, but for the outage, been provided by SONGS.

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198 WEM Phase 1A OB at 7-8.

199 SCE Phase 1A Reply Brief at 14.

13.2.1. Positions of the Parties

SCE suggests the following formula for each[200] hour in this category:

Q*P = Hourly Replacement Energy Cost or Foregone Sales

Where, Q is the quantity, the portion of the hourly net short (long) position attributed to the outage (in MWh) and P is the price for that hour ($/MWh).[201] Other parties agree with this basic formula.[202] SDG&E adds an additional term "O" that represents:

- "CAISO Allocated costs," in the context of replacement energy costs,[203] which are separable and which we address in the other market costs category below, and
- "lost revenue from RA sales" in the context of foregone sales,[204] which are also separable and which we address in the capacity-related costs section below.

This is a very simple and familiar formula: cost (or lost sales revenue) equals quantity multiplied by price. The calculation of the terms Q and P provokes more controversy.

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200 Note that SCE proposes a price elasticity adjustment to the term P in some hours. We address this adjustment below.

201 SCE-37 at 7.

202 In TURN-14 and in cross-examination, TURN witness Woodruff argues for changes about the calculation of the terms P and Q, implying acceptance of the basic formula. Similarly, in DRA-2, DRA makes a variety of recommendations about the terms P and Q, implying acceptance of the basic formula. Note that earlier versions of the utility testimony, to which DRA-2 responds, show the formula as Q*(P-F), where F represented avoided nuclear fuel costs. DRA-2 suggests that F should be zero. The utilities have agreed, in SCE-37 and SDGE-9B, to set F equal to zero, thus simplifying the formula to Q*P.

203 SDGE-9B at 5.

204 SDGE-9B at 7.

13.2.1.1. Q, Quantity

Q represents the amount of energy that must be bought, or could not be sold, for the hour due to the outage. SCE suggests that Q be limited to the amount of energy "that SONGS could have generated had it been available to operate that would have reduced [the utility's] net short position."[205] This limit encompasses two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic operating expectations, and 2) limiting the amount of energy attributed to each utility based on that utility's ownership share of SONGS. No party opposes this limit in concept. Q represents the approximate result of subtracting the utility's actual day ahead energy position from what the position would have been, had SONGS been available to operate. In some hours, the utility would be shorter due to the SONGS outage and have replacement energy costs; in others it would be less long and have foregone energy sales. In still other hours, when the utility was short by less than its share of the SONGS output, the utility had both replacement energy costs and foregone sales. This last possibility is not explicitly referenced in plain language by any party. However, the parties' various arguments about which costs do (or do not) constitute replacement power costs are related. For example, TURN's comments about assuming that "SONGS is always the marginal generation unit" appear to address this possibility.[206] TURN observes that D.05-12-040, which approved the replacement steam generators at

[205] SCE-2 at 18.

[206] TURN Phase 1A Reply Brief at 3, and 7-8

SONGS, relied on an SCE analysis that assumed the entire generation of SONGS, not limited by the utility's net open position.[207]

How to measure the utility's position is one key question. SCE proposes using the utility's actual position in the day-ahead time frame, specifically, "its final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity".[208] SDG&E agrees.[209] TURN, by contrast, suggests that use of the actual day ahead position creates "downward bias" in the estimate of Q. In response, SCE "contends that there are too many factors to consider to reliably assume a downward bias."[210]

SCE and SDG&E suggest that Q should be calculated using a 2.15% forced outage rate, based on a recent ten year average. SCE also notes this is consistent with the industry average 2% rate reported by the Nuclear Regulatory Commission.[211] SCE suggests that the forced outage rate should be applied equally in all hours (e.g. the assumed lost generation of SONGS would be reduced by 2.15% in each and every hour of the outage).[212] DRA, in contrast suggests a 1.21% forced outage rate, based on a five year average.[213] DRA alternatively suggests using the industry average 2% rate.[214]

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[207] TURN Phase 1A Reply Brief at 5, citing D.05-12-040 at 21-22

[208] SCE-2 at 21.

[209] SDGE-9B at 3

[210] SCE 37 at 19.

[211] SCE-37 at 7; SDGE-9B at 5.

[212] RT 1415:1-3.

[213] DRA-2 at 14.

[214] DRA Phase 1A OB at 6.

SCE suggests that Q should be limited by scheduled refueling and maintenance outages so that only the unit that would not have been on a scheduled outage is counted for replacement power cost calculations. SCE suggests the following scheduled outage dates:[215]

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

No party disputes the dates or the use of these scheduled outages to limit Q during those time periods.

Both utilities suggest that the Q applied to each of them individually should be limited to their respective ownership share of SONGS.[216] No party disputes this.

13.2.1.2. P, Price

P represents the price or the value to the utility of the energy that must be purchased or cannot be sold. SCE suggests using the "SP-15 day-ahead index prices" as reported by Platt's MegaWatt Daily.[217] SCE notes that it procures energy for bundled customers in many different timescales ranging from multi-year to hourly and that there is no single price point that accurately reflects its

[215] SCE-38 at 12.

[216] SDGE-9B at 3, SCE-38 at 2-3.

[217] SCE-38 at 3. Note that SP-15 refers to the region of the California electric grid to the South of Path 15. SP-15 includes the service territories of both SCE and SDGE, as well as the SONGS facility.

incremental costs.[218] SCE supports its position by asserting that the SP-15 day-ahead index represents costs for the utilities both as buyers and as sellers:

> SP-15 is an appropriate pricing point because the SONGS energy that would have otherwise been produced would have generally served SP-15 load. Additionally, bilateral transactions that SCE would make to cover bundled demand would generally be purchased with an SP-15 delivery or settlement price. Specifically, SP-15 day-ahead index prices are commonly used to settle financial transactions for energy transacted for delivery in southern California.[219]

SDG&E proposes the "SP-15 Trading Hub day-ahead prices" as published by the California Independent System Operator (CAISO), noting that this is the price SDG&E would receive from CAISO for its share of the SONGS output when SONGS was operating.[220] The CAISO trading hub price is calculated for each hour in the day, in contrast to the Platts SP-15 Index proposed by SCE, which is calculated for the on-peak and off-peak periods of each day.[221] SDG&E notes that it is "agreeable" to using the Platts SP-15 Index.[222]

DRA expresses a slight preference for the Platts SP-15 Index proposed by SCE and recommends that the same measure of P be used for both utilities. DRA notes that, although the difference between the two measures proposed by the Utilities is large in some hours, there is very little difference on average. DRA's

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218 SCE-37 at 16.

219 SCE-38 at 3.

220 SDGE-2 at 18.

221 RT 1442:14-1443:7.

222 SDGE Phase 1A Reply Brief at 6.

reasoning for this preference is based on the index's use to settle financial and physical transactions in SP-15.[223]

TURN and A4NR suggest that the utilities' respective Default Load Aggregation Point (DLAP) prices should be used for replacement energy costs and the SP-15 Existing Zone Generation Hub (SP-15 EZ-Gen) for foregone sales. The DLAP price represents prices paid by load in the CAISO markets and SP-15 EZ Gen represents prices paid to generators. [224] A4NR's rationale is that ex-post prices are preferable to ex-ante (e.g. the day-ahead Platts) for the purpose of calculating damages and that this approach would be using a load-based price (DLAP) for replacement energy and a generation-based price (SP-15 EZ-Gen) for foregone sales. TURN focuses on the "gap" between the two prices and argues that the simplicity of using a single price does not justify the decrease in accuracy. In support, TURN provides an SCE data response suggesting a 2.5% difference.[225] SCE notes that it is "not opposed" to this proposal "as a matter of principle," but raises the practical objection that the DLAP and SP-15 EZ-GEN prices are not detailed in the record.[226]

For hours with foregone energy sales, SCE proposes that P be modified as (P-E) where E is the "estimated price elasticity impact of SONGS not being available to operate (expressed in $/MWh)."[227] SCE calculated E for on-peak and

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[223] DRA-2 at 7-8.

[224] A4NR Phase 1A OB at 4-6; TURN Phase 1A OB at 7-9.

[225] TURN Phase 1A OB at 8, citing TURN-9, Question 13b.

[226] SCE Phase 1A Reply Brief at 19.

[227] SCE-37 at 8-9.

off-peak periods for each month based on a regression analysis.[228] SDG&E and TURN each conceptually agree with SCE's approach on this elasticity analysis, but are not able to offer detailed quantitative comment on SCE's estimates. TURN did note that "the results seemed reasonable."[229] No other parties have commented on the subject.

13.2.2. Discussion

We will adopt the formula proposed by SCE and supported by SDGE, TURN, and DRA, including the price elasticity adjustment for foregone sales. Basic economic reasoning suggests this formula: cost (or foregone sales) is equal to the quantity purchased (or not sold) multiplied by the unit price. We apply this formula as summarized in this table:

Hours when the net open position is	**Formula**	**Replacement Energy Cost or Foregone Energy Sales?**
Short	$Q_{short} *P =$	Replacement Energy Cost
Long	$Q_{long} *(P-E) =$	Foregone Energy Sales
Short by less than ownership share of SONGS energy	$Q_{short}*P =$	Replacement Energy Cost
	$Q_{long}*(P-E) =$	Foregone Energy Sales

13.2.2.1. Q, Quantity

Q is the net open position, in MWh, of the utility, up to its ownership share of SONGS energy. We agree with SCE that Q should be limited by two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic operating expectations, and 2) limiting the amount of

228 RT 1415:7-24.

229 RT 1454:17-24; RT 1574: 7-23.

energy attributed to each utility based on that utility's ownership share of SONGS. For hours when the utility's net open position is short (long), it buys (sells) energy to meet the needs of its customers; the amount of this short (long) position up to each utility's ownership share of the lost SONGS energy is the "replacement" energy ("foregone" sales). Amounts beyond the ownership share are ordinary purchases or sales that would have happened regardless of the outage. For hours when the utility's net open position is short by less than its ownership share of SONGS energy, the short position is shown as Q_{short}; the remaining portion of its ownership share is indicated as Q_{long} (i.e. $Q_{short} + Q_{long} = Q$ = the utility's ownership share of SONGS energy). This mathematical treatment of Q recognizes that the total amount of energy replaced (or sales foregone) is independent of the utility's net open position. Stated differently, the sum of energy replaced and sales foregone in each hour is equal to the utility's ownership share of SONGS energy that would have been produced (given operating assumptions discussed below) in that hour.

In all hours, Q should be limited based on realistic operating parameters of SONGS. We agree with parties that these limits are based on both forced and planned outages. We find that each SONGS unit had one planned outage during 2012 and that only the generation of the unit not on outage should be included in Q during the scheduled outage. The planned outages are:

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

We recognize that there is no single "correct" historical timeframe to consider in selecting an appropriate forced outage rate to assume for this analysis. The range presented to us is small (1.21% to 2.15%), changing the calculated costs in this category by less than one percent, and total replacement costs by an even smaller fraction. Further, we note that the replacement steam generators would represent a significant change in the SONGS facility, which calls into question the basic assumption that past experience at SONGS should be the guide. Therefore, we find that it is appropriate to use the industry average 2% forced outage rate reported by the Nuclear Regulatory Commission.

Finally, we agree with SCE and SDG&E that measuring each utility's net open position based on its "final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity" is appropriate. We agree with TURN that this likely does introduce a downward bias because, as SCE admits, the utilities procure energy on many different timescales including products that could have been purchased during the outage for later parts of the outage more than one day forward. However, we see no viable, analytically rigorous alternative based on the record before us.

13.2.2.2. P, Price

P represents the price or the value to the utility of the energy that must be purchased or cannot be sold. We agree with TURN and A4NR that it is worthwhile to use the DLAP price for replacement energy costs and the SP-15 EZ-Gen price for foregone sales. This avoids any "downward bias" associated with using a price that does not match the transaction (i.e. generation based price for a purchase for load, or vice versa). We recognize that this choice imposes a small additional analytic burden on the parties, but believe this work is justified by the increased accuracy in the calculation.

We agree that a price elasticity adjustment, as suggested by SCE, is appropriate for foregone sales, in the form of P-E. The adjustment originally calculated by SCE was intended to modify the Platts SP-15 Index, and will need to be recalculated for the SP-15 EZ-Gen price. However, we see no reason for the basic mechanics of the calculation to change. The Utilities shall calculate a new adjustment, E, for the SP-15 EZ-Gen price, using a regression analysis as presented in work papers and testimony in Phase 1A. The analysis should calculate E for on-peak and off-peak periods of each month

13.3. Capacity-Related Costs

SCE describes three types of capacity costs related to the SONGS outages:[230]

- CAISO Capacity Procurement Mechanism (CPM) charges. CPM charges are allocated to bundled customers based on their load ratio share in certain Transmission Access Charge Areas.
- CAISO Standard Capacity Product (SCP) penalty charges for forced outages. Other Resource Adequacy (RA) resources that qualified for an availability bonus under the SCP during 2012 received bonus payments funded by the SONGS SCP penalty. SCE netted the bonuses it received against its penalty charges.
- Replacement RA capacity. In order to reduce SCP penalty charges, SCE purchased some replacement RA capacity.

CPM costs were incurred related to the outages of both units. The Unit 2 outage, because it was classified as planned, did not result in SCP penalty charges or replacement RA capacity purchases.[231]

SDG&E describes the same three capacity cost categories.[232] However, we must also address the foregone RA sales that SDG&E notes in its testimony.[233]

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[230] SCE-38 at 8-9

[231] SCE-38 at 9

[232] SDGE-9B at 7-8

[233] SDGE-9B at 7

Lost RA value is a broader issue than presented in the SDG&E testimony. Based on the RA rules that were adopted in D.06-07-031 (see table below), the extension of the Unit 2 scheduled outage would prevent that unit from being used to satisfy RA requirements for any month in 2012, after the outage became known. By this rule, both SCE and SDG&E may have lost the value of Unit 2's RA capacity for each month of 2012, excluding January and February for which the RFO was originally scheduled. However, the record before us does not describe which months the Unit 2 RA value was actually lost. It is reasonable to assume that RA value was lost for July to September, when RA requirements are highest. Unit 3's outage, classified as forced rather than scheduled, did not diminish that unit's RA value by this rule. D.06-07-031 summarizes the scheduled outage counting rule as follows:[234]

Time Period	Description of How Resource Would Count at Time of the Showing
Summer May through September	Any month where days of scheduled outages exceed 25% of days in the month, the resource does not count for RAR. If scheduled outages are less than or equal to 25% of the days in the month the resource does count for RAR.
Non-Summer Months October through April	For scheduled outages less than 1 week, the resource counts towards RA obligations. For scheduled outages 1 week to 2 weeks, the amount counted for RAR is prorated using the formula: [1 - (days of scheduled outage/days in month) - 0.25] * NQC in MW = NQC that can count towards an LSE's RA obligation The formula will allow resources to count between 50% and 25% of NQC. For scheduled outages over 2 weeks, the resource does not count for RAR.

Providing RA capacity to meet requirements is a direct cost of serving bundled customers' capacity needs and to the extent that the net cost of meeting RA requirements increased due to the SONGS outage, the increase is a replacement power cost. We find that each utility's ownership share of Unit 2's RA value (Net Qualifying Capacity, or NQC) multiplied by the monthly system

[234] D.06-07-031 at 10.

RA price is the appropriate measure of this lost RA value, for July through September in 2012.[235] This measure assumes that in each month either replacement RA was procured or RA sales were foregone, or both. The record before us does not clearly show RA prices for each month. In calculating lost RA value, each utility shall use the average price of its RA-only[236] transactions during calendar year 2012 for July through September of 2012.

DRA notes that both utilities describe the same cost categories.[237]

We find that all three of the capacity-related costs identified by SCE, as well as any foregone RA sales, are replacement power costs. No party disputes that each of these categories represents a capacity cost incurred on behalf of bundled customers as a result of the outage. As discussed above, SCE argues that capacity costs should not be counted as replacement power, but does not provide a persuasive rationale.[238] SCE cites two prior Commission decisions (post-restructuring) that use replacement power costs as a penalty for unreasonable forced outages and uses them to support its assertion that replacement power costs should be limited to replacement energy.[239] SCE neglects to mention that the outages contemplated in these decisions are of a

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[235] Even though SONGS is a "local" RA resource, the local premium is only valuable in year-ahead RA contracts and prices. The month-ahead RA program does not explicitly measure local RA.

[236] By RA-only, we intend to isolate the price paid for RA, exclusive of other attributes. Therefore, to perform this calculation, the utilities should exclude contracts that include other values, such as: tolling, combined heat and power, renewables, and qualifying facilities.

[237] DRA-2 at 16.

[238] See: **Error! Reference source not found.**.

[239] SCE Phase 1A OB at 4, citing D.10-07-049 and D.11-10-002.

much shorter duration than in the instant case. This is an important distinction due to the incentive for grid operators to take action, for example via CPM, to replace the capacity on outage when that outage may have a long duration. Further, in the market, as it existed in 2012, outages of any duration have a different impact on capacity-related costs than outages during the time periods discussed in the previous decisions. The SCP, and by extension SCP penalties and the need for replacement RA, was created in the CAISO markets in January, 2010 after the outages in the decisions cited by SCE.[240] SDG&E cites one similar decision, but its subject is also a short duration outage prior to the SCP.[241]

TURN suggests adding an additional capacity-related line item from the outage memorandum accounts: the Demand Response (DR) subaccount (line 40).[242] SCE argues that the DR at issue was "exclusively designed as a grid reliability measure" and should not be considered as replacement power because it was not "to meet bundled customer demand."[243] As TURN observes, this distinction is "artificial" – the program was designed to alleviate reliability concerns that were at least in part caused by the SONGS outage.[244] Indeed, this OII directed that the only DR tracked in the subaccount is the DR "specifically

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[240] *California Independent System Operator Corporation* (June 26, 2009) 127 FERC ¶ 61,298 (Order Accepting in Part and Rejecting in Part Tariff Revisions Subject to Modification) at 1.

[241] SDGE Phase 1A Reply Brief at 2, citing D.12-03-014.

[242] TURN-14 at 8.

[243] SCE Phase 1A OB at 14, partly referring to RT 1361: 9-10.

[244] TURN Phase 1A OB at 9-10, referencing TURN-4 at 15.

implemented to address the loss of SONGS Units 2 and 3 capacity."[245] We find that the DR subaccount is an element of replacement power costs.

13.4. Other Market Costs

In this section, we address other market costs individually.

As discussed above, we view CRRs as a valid component of the Utilities' risk hedging activities. We will not treat net changes in values of previously held CRRs as a replacement power cost. SDG&E notes that it procured CRRs in the monthly CAISO auctions after the outages to manage outage-related congestion costs and that it treats these CRRs as a component of 2012 replacement power costs.[246] We agree -- the net cost of CRRs purchased during 2012 in response to the outages is a replacement power cost.

Real Time Imbalance Charges were charged for the early hours of the outage (in January 31 and February 1 of 2012), when the actual output of SONGS deviated from its schedule in the CAISO markets. Auxiliary Load charges were incurred for load at the facility for the hours when SONGS was not generating during 2012. When SONGS operated, these auxiliary loads were met by SONGS generation. Auxiliary Load is billed by the CAISO through the Real Time Imbalance Charges. Although the Utilities report these two categories differently, they should be proportional to the ownership share of the facility.[247]

The CAISO's Participating Intermittent Resources Program (PIRP) allocates certain charges to all uninstructed negative deviations in the market.

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[245] OII.12-10-013 at 12-13.

[246] SDGE-9B at 5.

[247] RT 1422:25 – 1423:16.

Auxiliary load is treated as such a deviation, and therefore triggers PIRP charges.[248]

The Real Time Imbalance, Auxiliary Load, and PIRP costs would not have been incurred, except for the SONGS outage, in any hour that one or both units would have been scheduled to generate. Therefore we find that these are replacement power costs.

13.5. TURN Proposal for Supplemental Modeling

In its Opening Brief, TURN "offers an alternative approach to the calculation of replacement power costs." The approach is "that each utility be required to perform the specified modeling . . . and make an additional filing subject to comment by the parties." The modeling would calculate energy costs, generation revenues, and CRR costs and revenues by comparing "SONGS OUT" and "SONGS IN" scenarios, based on recorded quantities and actual or estimated prices.[249] TURN argues that this approach avoids "downward biases" found in the approaches suggested by the Utilities.

The Utilities argue against this approach on both procedural (e.g. timing) and practical (e.g. large number of required assumptions) grounds.[250] We agree with the Utilities' practical arguments. Simply stated, we do not have convincing evidence before us that any likely improvement in the accuracy of replacement power cost estimates justifies the considerable extra effort to pursue this modeling approach.

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[248] RT 1424:16 - 1425:8.

[249] TURN Phase 1A OB at 13-15.

[250] See SDGE Phase 1A Reply Brief at 4-6, SCE Phase 1A Reply Brief at 19-23.

13.6. Other Miscellaneous Proposals

WEM alleges that any expenses related to Huntington Beach Units 3 and 4 are illegal, and therefore are not replacement power and should be disallowed.[251] This is outside the scope of this Investigation. Further, SCE explains that it was not directly involved in the Huntington Beach transactions and that CAISO was the purchasing entity.[252]

WEM argues that the Utilities have failed to comply with the Loading Order.[253] This is out of scope.

13.7. Supplemental Exhibit Calculating Replacement Power Costs

In order to implement the replacement power calculations as adopted herein, the Utilities must each recalculate their replacement power costs. As stated above, we intend to have the estimate available for use in future phase of this proceeding (tentatively Phase 3). Therefore, we direct the Utilities to each serve a preliminary Phase 3 exhibit, including summary tables of these calculations within 45 days of today's decision. The summary tables shall contain at least the following details for each month of 2012 and other specified periods, all in 2012 dollars:

- Replacement Energy Cost,
- Foregone Energy Sales,
- Price elasticity adjustment, E, to SP-15 EZ-Gen price for on-peak and off peak periods for each month,

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[251] WEM Phase 1A OB at 4 and 24.

[252] SCE Phase 1A Reply Brief, RT 1391-1393.

[253] WEM Phase 1A OB at 24-25, citing e.g. D.12-01-033.

- CPM Charges,
- SCP Penalty Charges,
- Replacement RA,
- Foregone RA Sales,
- DR Costs,
- PIRP, Real Time Imbalance, and Auxiliary Load Charges, and
- Net Cost of SONGS-Related CRR Purchases.

In addition to the monthly periods, these items shall be calculated for each of the following periods:

- Calendar year 2012,
- Beginning of the SONGS Outage (1/31/2012) through 12/31/2012, and
- Beginning of the SONGS Outage (1/31/2012) through 10/31/2012.

Following the Utilities' submission of these exhibits, parties may serve reply testimony, if, and only if, they allege that the Utilities' calculations do not comply with today's decision or contain calculation errors. Such reply testimony will be due 45 days after the Utility testimony. If any reply testimony is served, rebuttal testimony may be served 20 days later. The assigned ALJs may modify this schedule. Neither the original Utility exhibits nor any reply or rebuttal testimony may be used as an attempt to relitigate any Phase 1A issue. The focus of the exhibits shall be exclusively on recalculating replacement power costs in compliance with today's decision.

14. Revenue Requirements and Refunds

Today's decision segregates 2012 SONGS related costs into three groups: adopted as reasonable costs for recovery, unreasonable costs that shall be refunded in 2014 rates, and costs for which the final reasonableness review shall occur in Phase 3. These adjustments and the resulting 2012 revenue requirement reduction are summarized below:

Summary of Adopted Ratemaking			
100% share, 000s of 2012$			
Cost Category	Adopted	Refund in 2014 Rates	Review in Phase 3
Base O&M	$273,867	$73,880	
SGIR O&M	$18,353		$122,603
Other O&M (Corp. Support, IT, Severance)	$1,663	$4,527	
Subtotal	$293,883	$78,407	$122,603
RFO O&M	$45,077		
Seismic	$4,077		
Capital Expenditures	$134,080		
Capital Additions	($33,520)	($500)	
Replacement Power			To be calculated
2012 Revenue Requirement due to O&M and Capital Adjustments		($93,522) SCE: ($74,222) SDG&E: ($19,300)	

The Utilities shall refund the excess revenue requirement identified by the Commission herein, collected in rates for 2012 expenses, through each utilities' established base rate balancing mechanism, to become effective on January 1, 2014. In addition, for rates collected applicable to SGIR incremental expenses, these funds shall be separately accounted for and interest accrued at the one-year Treasury rate for the benefit of ratepayers should the Commission find in a later phase these funds should also be refunded.

15. Comments on the Proposed Decision

The proposed decision of the ALJs in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ______________ and reply comments were filed on ____________ by ___________.

16. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and ALJ Kevin Dudney and ALJ Melanie M. Darling are the assigned ALJs in this proceeding.

Findings of Fact

1. On January 31, 2012 when the Unit 3 (U3) leak was discovered, Unit 2 (U2) was about half-way through its scheduled refueling outage where significant inspections, testing, and repairs take place.
2. On February 12, 2012, SCE confirmed a leak in U3 Steam Generator (SG) tube; additional testing identified several types of tube wear, including significant Tube-to-Tube wear (TTW) in the U-tube region of the SG.
3. On March 13, 2012, SCE was aware that eight U3 tubes failed in-situ pressure testing due to TTW.
4. On March 23, 2012, SCE submitted a SG Return-to-Service (RTS) Action Plan to NRC outlining its commitments to corrective actions before restarting either unit; at the time SCE did not know the cause or extent of tube wear in the steam generator tubes.
5. On March 27, 2012, U.S. Nuclear Regulatory Commission (NRC) sent SCE a Confirmatory Action Letter (CAL) that notified SCE it could not restart either unit until SCE completed a list of actions and NRC completed its review of the actions, including determining causes of TTW.

6. SCE knew the CAL would remain in effect until the NRC had (1) reviewed SCE's response, including responses to staff questions and the results of SCE's evaluations, and (2) NRC had written its conclusion that the units could operate safely without undue risk to public health and safety, and the environment.

7. In early 2012, TTW was unknown; SCE considered TTW as the most significant and complex phenomena, and a key barrier to restart of U2.

8. SCE completed all, or nearly all, of the work related to the U2 refueling outage before SCE knew the potential for serious damage in that unit.

9. In March 2012, SCE developed a plan to postpone, cancel, and re-schedule capital projects; SCE also began work on short-term and long-term repair options.

10. SCE knew or should have known by March 15, when it confirmed tube-to-tube wear in Unit 3, that a potential design defect was present in both units and thus fault could become an issue to rate recovery.

11. SCE's extensive U3 testing completed April 15, 2012, found more than half of the TTW indications in each SG had maximum measured depths exceeding the 35% plugging limit in the technical specifications.

12. On April 23, 2012, SCE issued a U2 tube wear Root Cause Analysis (RCA) which identified the cause of TTW as Fluid Elastic Instability (FEI).

13. On April 26, 2012, SCE Board of Directors was told by SCE managers that U2 return-to-service (RTS) RTS was scheduled for June 1, 2012, and U3 on June 30, 2012.

14. SCE's assumption that U2 could restart in 2012 served as a basis to prioritize work for the plant staff, the operators, and others.

15. SCE did not consider alternative courses of action for U2, other than the restart plan.

16. Cost considerations were not a dominant factor in SCE's analysis of its intended actions for U2.

17. On May 7, 2012, SCE issued U3 RCA which included identification of TTW in U2 and U3.

18. SCE knew or should have known by May 7, 2012, when it confirmed tube-to-tube and three other types of tube wear in Unit 2, that pursuit of a restart plan for U2 was not in the interests of immediately restoring power generation for the benefit of ratepayers

19. In June 2012, SCE began planning to put U3 into Preservation Mode, which maintains the unit in a condition that would allow future refueling and restart, assuming a long-term repair was completed.

20. During the first few months of 2012, SCE worked closely with the NRC, MHI, and its contracted experts to investigate the damage and to develop operational assessments to support a limited restart of U2 for the purpose of testing impact on the SG tubes.

21. SCE's decision to restart U2 was not part of normal operations for an operating generation facility because it was not reasonably foreseeable that the unit would return to full generation in 2012.

22. In July 2012, SCE created a long term repair team for both units.

23. On October 3, 2012, SCE submitted its response to CAL; NRC identifies 6 -7 month window for review, inspections, response to staff information requests, public meetings, etc.

24. On December 5, 2012, the Atomic Safety Licensing Safety Board held hearing to determine whether SCE will need a license amendment to try U2 restart plan

25. On December 14, 2012, Mitsubishi Heavy Industries (MHI), which designed & manufactured the replacement steam generators, sent two progress letters to SCE regarding development of long-term repair options.

26. On December 20, 2012, MHI provides SCE with long-term repair options and recommendations.

27. The primary purpose of SCE's U2 restart plan was a limited theoretical test to gather data for long-term repair options, not for electric generation.

28. SCE bills SDG&E for its pro rata share of SONGS-related expenses; SG&E also has internal-only expenses related to its ownership interest in SONGS.

29. SCE has not credited the $3.96 million in 2012 savings from staff reductions to the overall calculation of O&M.

30. Of the total $488,702 million recorded (100% $2012) for O&M costs, $347.747 million is recorded as Base-Routine, $140.955 million as SGIR-related.

31. By early May 2012, SCE knew or should have known that it was not reasonably foreseeable that Unit 2 would return to producing electricity in 2012 or even that a short-term restart was viable.

32. In order to reasonably account for O&M costs incurred as a result of SCE's not well-considered decision to maintain all, or nearly all, operating staff through the end of 2012, O&M costs recoverable in rates should gradually decrease beginning in June 2012.

33. SCE recorded $140.855 million (100%) for 2012 incremental SGIR expenses, including $8.555 million re-allocated post-hearing from Base O&M.

34. SCE collected some SGIR-related expenses in rates because it viewed them as normal O&M or capital costs.

35. The seismic studies approved by D.12-05-004 are not directly related to relicensing; they are related to regulatory requirements.

36. The Commission preliminarily authorized SCE to make $189.2 million ($2012, 100%) in SONGS-related capital expenditures; SCE actually recorded a total of $167.6 million for all types of projects, including the RFO and SGIR expenses.

37. More than $89 million (53.5%) of total capital expenditures occurred between January and April, 2012.

38. Some capital expenditures were necessary during 2012, even though the reactor units were not operating, because the NRC operating license requires SCE to maintain many systems in order to protect the safety of the plant, its workers and the public.

39. SCE's effort to suspend, cancel, and re-schedule some projects was inadequate to reflect the overall reduction of capital projects that should have occurred at SONGS.

40. Rate-based 2012 capital revenue requirements exceed preliminary allowed amounts for both SCE and SDG&E by a combined total of $41.8 million.

41. SCE's evidence is incomplete as to the extent that SGIR-related and U2 RFO capital projects are recorded as in-service and added to rate base in 2012.

42. The evidence does not establish that SCE knew in 2012 that it would decide in 2013 to permanently shut down the SONGS facility.

43. SCE did not calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012, but said it could develop an approximate estimate using the lead-lag days adopted in the GRC.

44. SDG&E recorded $60.492 million of SONGS-related costs not included in the SONGS portion of SCE's 2012 GRC or in SCE's OII testimony.

45. The costs of SCE's Customer Outreach and Emergency preparedness programs are part of the company-wide GRC review, primarily through budgets for Local Public Affairs and Corporate Communications.

46. The requirements for emergency preparedness followed by SCE, and other operators of commercial nuclear plants in the United States, are established by the NRC, Federal Emergency Management Agency (FEMA), and certain state agencies.

47. It is in the public interest for SCE to expand its public education about SONGS and the future decommissioning beyond the 20-mile zone, to 50 miles, for the immediate future.

48. In 2011, SCE expected two RFOs to occur in 2012 and included $102.606 million in 2012 rates for these RFOs (100% share).

49. SDG&E included $28.7 million in rates for its share of two RFOs in 2012.

50. Only one RFO, the U2 Cycle 17 RFO, occurred during 2012 at a cost of $45.1 million, resulting in an effective over-collection of $57.5 million (100% share).

51. SDG&E recorded $9.1 million for the 2012 RFO, $19.6 million less than collected.

52. The utilities' costs of $45.1 million (100% share) for the U2 Cycle 17 RFO during 2012 were reasonably incurred.

53. Any amount collected beyond the $45.1 million for 2012 RFOs is an over-collection.

54. SCE seeks to refund its over-collection via its 2013 ERRA forecast proceeding.

55. SDG&E has refunded its over-collection via Advice Letter 2416-E.

56. SCE's decision to place new fuel in the U2 core during U2 Cycle 17 RFO was reasonable.

57. For purposes of calculating 2012 replacement power costs in Phase 1A of this proceeding, the definition of replacement power is the net increase in costs to the utility of meeting its energy and capacity obligations to bundled customers. This definition includes: the cost of replacing potential generation and lost revenues from potential sales; capacity and demand response costs allocated to bundled customers, to the extent these costs are clearly linked to the SONGS outage; the net cost of Congestion Revenue Rights (CRRs) purchased in response to the outages; and onsite SONGS loads. This definition excludes energy efficiency programs and the changes in the value of pre-existing utility hedges including CRRs.

58. The formula detailed in the following table is appropriate for calculating replacement energy cost and foregone sales, where: Q represents the SONGS outage-related portion of the hourly net open position in megawatt-hours, P represents the energy price in dollars per megawatt-hour, and E represents a price elasticity adjustment in dollars per megawatt-hour.

<table>
<tr><th>Hours when the net open position is</th><th>Formula</th><th>Replacement Energy Cost or Foregone Energy Sales?</th></tr>
<tr><td>Short</td><td>$Q_{short} *P =$</td><td>Replacement Energy Cost</td></tr>
<tr><td>Long</td><td>$Q_{long} *(P-E) =$</td><td>Foregone Energy Sales</td></tr>
<tr><td rowspan="2">Short by less than ownership share of SONGS energy</td><td>$Q_{short}*P =$</td><td>Replacement Energy Cost</td></tr>
<tr><td>$Q_{long}*(P-E) =$</td><td>Foregone Energy Sales</td></tr>
</table>

59. Q is appropriately limited by two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic

operating expectations, and 2) limiting the amount of energy attributed to each utility based on that utility's ownership share of SONGS.

60. Each SONGS unit had one planned outage during 2012, for the dates below.

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

61. It is reasonable that only generation for the unit not on outage be included in Q during each of the scheduled outages.

62. It is appropriate to use the industry average 2% forced outage rate reported by the Nuclear Regulatory Commission for calculating Q.

63. Measuring each utility's net open position (Q) based on its final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity is appropriate.

64. It is reasonable to use the Default Load Aggregation Point (DLAP) price for replacement energy costs and the South of Path 15 Existing Zone Generation Hub (SP-15 EZ-Gen) price for foregone sales.

65. A price elasticity adjustment is appropriate for foregone sales.

66. There are five types of capacity-related costs that are replacement power costs: California Independent System Operator (CAISO) Capacity Procurement Mechanism (CPM) charges, CAISO Standard Capacity Product (SCP) penalty charges, replacement Resource Adequacy (RA) capacity, foregone RA sales, and Demand Response (DR) specifically implemented to address the loss of SONGS.

67. It is reasonable to assume that RA value was lost for July to September of 2012, when RA requirements are highest.

68. Each utility's ownership share of Unit 2's RA capacity value (Net Qualifying Capacity) multiplied by the monthly system RA price is the appropriate measure of this lost RA value, for July through September in 2012.

69. It is reasonable for each of the Utilities to use the average price of its RA-only transactions concluded during calendar year 2012 for July through September of 2012, or any month therein, as the RA price for July through September 2012.

70. The Real Time Imbalance, Auxiliary Load, and PIRP costs would not have been incurred, except for the SONGS outage, in any hour that one or both units would have been scheduled to generate, and therefore these costs are replacement power costs.

Conclusions of Law

1. During January and February, SCE acted as a prudent operator of SONGS to detect the U3 leak, identify the source of the leak, inspect all of the U2 and U3 tubes for damage, investigate the causes of excessive and unexpected wear, and to assess whether repair is a reasonable option.

2. SCE's decision-making process was not reasonable or sound when the utility decided after May 7, 2012 to pursue RTS for U2 as soon as possible.

3. SCE's decision in May 2012 to retain the staff required for a fully operational facility, resulting in large O&M expenses, was unreasonable.

4. The record does not establish that costs associated with the restart and long-term repair options (SGIR) are routine O&M for which it would be just and reasonable to collect immediate recovery from ratepayers.

5. It is reasonable for savings realized from employee layoffs to be credited to ratepayers as part of the overall costs subject to rate recovery for 2012 O&M.

6. Beginning in June 2012, 10% of O&M shall be re-allocated to SGIR for further review as SGIR-related expenses in Phase 3, followed by 20% in July and so on until November and December 2012 when 40% of recorded O&M will remain in rates.

7. The total amount of reasonable 2012 SONGS-related O&M is $292.030 million, $96.97 million less than the amount preliminarily authorized in the GRC ($389.0 million).

8. It is reasonable to defer the final reasonableness review of 2012 incremental costs related to the outages of the steam generators to Phase 3 in the context of the overall SGRP and SCE's management of the project.

9. It is reasonable to apply a 20% reduction to recorded capital expenditures to establish the necessary and reasonable amount to maintain the units in a safe and secure condition, or to meet federal and state regulatory requirements.

10. It is reasonable for ratepayers to receive interest on previously collected SGIR expenses which have not yet been found by the Commission to be reasonable, nor were they preliminarily authorized by the Commission.

11. Approximately $134.08 million (80%) of 2012 total recorded capital expenditures are reasonable, including expenditures related to the U2 RFO.

12. It is reasonable to apply the 20% reduction in approved capital expenditures as a proxy for excess capital projects moved to rate base in 2012, to remove this amount from the rate base, and the associated revenue requirement is determined to be unreasonable for 2012.

13. It is not reasonable to impute knowledge of SCE's June 2013 decision to shut down SONGS permanently, to SCE during 2012.

14. It is not reasonable to prevent the Utilities from accruing AFUDC in 2012 for SONGS-related Construction Work In Progress.

15. In order to capture additional SONGS-related costs, it is reasonable for SCE to calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012.

16. The Commission's interim finding that SDG&E's internal SONGS-related costs of $60.5 million are reasonable does not preclude the Commission's subsequent review of SGRP and SGIR costs from the final review to come.

17. There is no evidence that that SCE has failed to comply with any federal, state, or county regulations regarding emergency preparedness.

18. It is reasonable for SCE to expand its public outreach activities into the 50-mile radius surrounding SONGS during the transition to decommissioning activities.

19. The ratemaking treatment approved by D.12-05-004 for the SONGS seismic studies should not be changed by today's decision.

20. The utilities should be authorized to recover their actual, reasonably incurred costs for the U2 Cycle 17 RFO of $45.1 million (100% share).

21. The utilities should be required to refund to ratepayers any amount previously collected for 2012 RFOs beyond the actually incurred $45.1 million.

22. To prepare for using the replacement power cost calculation method adopted here, the utilities should be required to serve Phase 3 exhibits detailing their calculation of their replacement power cost using the adopted method. The exhibits should also include other detailed information as specified in the body of today's decision.

23. Reply and rebuttal testimony in response to the Utilities' Phase 3 replacement power exhibits should be permitted if, and only if, any party alleges that the Utilities' exhibits do not comply with today's decision or contain calculation errors.

24. No party should be allowed to use the Phase 3 replacement power exhibits to relitigate any Phase 1A issue.

25. The assigned ALJs should be permitted to modify the schedule for the Phase 3 replacement power testimony.

ORDER

IT IS ORDERED that:

1. Application 13-01-016 is granted to the extent set forth in this Decision. Southern California Edison Company's preliminarily allowed 2012 revenue requirement derived from expenses related to the San Onofre Nuclear Generation Stations is reduced by approximately $74 million. Southern California Edison Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the revised company revenue requirement of $5.671 billion as set forth in Appendix G, effective January 1, 2012.

    a. As part of the revenue requirement calculation ordered in paragraph 3, Southern California Edison Company shall calculate a separate estimate of Cash Working Capital requirements attributable to San Onofre Nuclear Generation Stations in 2012 using the lead lag and other relevant inputs adopted for the company in its 2012 General Rate Case.

2. Application 13-03-013 is granted to the extent set forth in this Decision. San Diego Gas & Electric Company's preliminarily allowed 2012 revenue requirement derived from expenses related to the San Onofre Nuclear Generation Stations is reduced by approximately $19 million. San Diego Gas & Electric Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the revised revenue requirement effective

January 1, 2012.

a. San Diego Gas & Electric Company is also authorized to recover in rates $60.4 million in additional expenses incurred solely as a result of San Diego Gas & Electric Company's ownership interest and oversight responsibilities, and which are not included in Southern California Edison Company's invoiced pro rata share of San Onofre Nuclear Generation Stations operational expenses.

3. Within 10 days of the effective date of this decision, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the Utilities), in consultation with the Commission's Energy Division, shall each prepare a revised 2012 revenue requirement based on input of the reduced expenses and reduced rate base authorized herein, into each utility's 2012 General Rate Case model. The Utilities shall each submit the revenue requirement to the Commission as a Tier 1 Advice Letter, and serve the Advice Letter on the service list for these consolidated proceedings.

4. Within 20 days of the effective date of this decision, Southern California Edison Company and San Diego Gas & Electric Company shall submit revised tariff sheets to implement the revised 2012 revenue requirement. The revised tariff sheets shall become effective on filing, subject to a finding of compliance by the Commission's Energy Division, and shall comply with General Order 96-B.

5. Southern California Edison Company and San Diego Gas & Electric Company shall re-calculate the amount of 2012 operations and maintenance expenses directly related to steam generator inspection and repair, as set forth in this Decision, and identify the portion which was previously collected in rates. The Utilities shall separately account for the steam generator inspection and repair expenses previously collected, and those not yet collected in rates, in the San Onofre Nuclear Generation Station (Outage) Memorandum Accounts.

6. The Utilities shall accrue interest on collected steam generator inspection and repair funds at the one-year Treasury rate for the benefit of ratepayers to protect the value of the funds until the Commission completes its Phase 3 review of all expenses related to the replacement steam generators. All steam generator inspection and repair expenses, including those not recovered by the Utilities in rates, shall continue to be tracked in the San Onofre Nuclear Generation Station (Outage) Memorandum Accounts.

7. Within 90 days of the effective date of this decision, Southern California Edison Company shall develop a strategy for expanding public education activities about San Onofre Nuclear Generation Station and the future decommissioning to the public within a 50-mile radius of San Onofre Nuclear Generation Stations through 2016. Southern California Edison Company shall be particularly sensitive to pockets of alternative language users and coordinate with community-based organizations to ensure wide distribution of information to the public about the status of San Onofre Nuclear Generation Stations and its planned decommissioning. Southern California Edison Company shall submit the proposed strategy and implementation schedule to the Commission as an Information-Only Filing, as defined in Section 3.9 of the General Rules of General Order 96-B and serve it on the service list for these consolidated proceedings.

8. The ratemaking treatment approved by Decision 12-05-004 for the seismic studies shall remain unchanged by today's decision.

9. Southern California Edison Company and San Diego Gas & Electric Company are authorized to recover their respective shares of $45.1 million (100% share) for the Unit 2 Cycle 17 Refueling Outage that occurred in 2012.

10. Southern California Edison Company and San Diego Gas & Electric Company shall refund to ratepayers any amount previously collected for 2012

Refueling Outages beyond this $45.1 million.

a. Southern California Edison Company shall refund any remaining over-collection in its 2014 rates to the extent that the refund has not previously occurred in 2013 rates based on its 2013 Energy Resource Recovery Account filings.

b. San Diego Gas & Electric Company shall refund any remaining over-collection in its 2014 rates to the extent that the refund has not previously occurred in 2013 rates based on its Advice Letter 2416-E.

11. Within 45 days of the effective date of this decision Southern California Edison Company and San Diego Gas & Electric Company shall each serve a preliminary Phase 3 exhibit, including summary tables of their 2012 replacement power cost calculations according to the method adopted in today's decision. The summary tables shall include at least the details specified below:

a. Replacement Energy Cost;

b. Foregone Energy Sales;

c. Price elasticity adjustment, E, for on-peak and off peak periods for each month;

d. Capacity Procurement Mechanism Charges;

e. Standard Capacity Product Penalty Charges;

f. Replacement Resource Adequacy;

g. Foregone Resource Adequacy Sales;

h. Demand Response Costs;

i. Participating Intermittent Resource Program, Real Time Imbalance, and Auxiliary Load Charges; and

j. Net Cost of Related Congestion Revenue Rights Purchases.

12. Following the Utilities' submission of these preliminary Phase 3 exhibits, parties may serve reply testimony, if, and only if, they allege that the Utilities' calculations do not comply with today's decision or contain calculation errors.

Such reply testimony will be due 45 days after the Utility testimony. If any reply testimony is served, rebuttal testimony may be served 20 days later. The assigned ALJs may modify this schedule. Neither the original Utility exhibits nor any reply or rebuttal testimony may be used as an attempt to relitigate any Phase 1A issue.

13. All rulings made by the assigned Commissioner and/or Administrative Law Judge(s) to date are affirmed, all motions applicable to Phase 1 and Phase 1A and not yet ruled upon are deemed denied.

14. Investigation 12-10-013, Application 13-01-016, Application 13-03-005, Application 13-03-013, and Application 13-03-014 remain open.

This order is effective today.

Dated ______________________________, at San Francisco, California.

Appendix A

Southern California Edison Company's Year End 2012 SONGSMA Report

SOUTHERN CALIFORNIA EDISON COMPANY
SONGS 2&3 Outage Memorandum Account - February 2013
I.12-10-013
($000)

		2012												
		January	February	March	April	May	June	July	August	September	October	November	December	YTD
1.	**I. Base Capital Cost Subaccount**													
2.	Capital Expenditures	10,229	38,143	13,727	9,450	7,984	6,970	8,853	8,048	8,647	5,306	10,392	5,857	133,606
3.	CWIP Balance	284,283	330,425	194,542	173,272	173,400	182,300	191,100	191,900	198,800	203,465	210,279	216,652	216,652
4.	Rate Base - End of Month	559,991	553,385	636,466	643,875	637,547	657,441	645,621	649,052	636,617	621,858	625,236	638,655	
5.	Depreciation	5,494	5,491	5,505	6,483	7,290	7,106	7,054	7,090	7,143	7,161	7,195	7,319	80,331
6.	Taxes on Income	(1,069)	1,073	43,921	22,886	4,899	775	538	(16,702)	1,268	(1,300)	(10,262)	(264)	45,762
7.	Ad Valorem Taxes	493	493	493	493	493	493	601	601	601	601	601	601	6,568
8.	Return	4,099	4,053	4,331	4,661	4,665	4,714	4,744	4,713	4,680	4,581	4,540	4,601	54,382
9.	Subtotal Revenue Requirement	9,017	11,110	54,250	34,522	17,347	13,089	12,937	(4,298)	13,693	11,043	2,074	12,257	187,042
10.	**II. Steam Gen Replacement/Removal Capital Cost Subaccount**													
11.	Capital Expenditures -Replace	(689)	231	1,916	291	1,409	(1,473)	71	699	621	42	1,585	6,567	11,268
12.	Capital Expenditures -Remove	-	-	127,343	-	-	(33,595)	-	-	1,057	11,671	49	1,257	107,783
13.	CWIP Balance - Replace	90,600	91,300	-	128,479	98,314	-	93,900	95,300	-	(11,313)	1,198	6,749	6,749
14.	CWIP Balance - Remove	-	-	94,805	-	-	93,700	-	-	94,800	57,041	251	1,465	1,465
15.	Rate Base - Replace - End of Month	528,435	524,141	519,846	515,552	511,258	510,188	505,868	501,548	498,977	494,640	479,247	475,058	
16.	Rate Base - Remove - End of Month	(31,787)	(31,806)	(31,933)	(31,956)	(32,038)	(31,970)	(31,977)	(32,014)	(32,066)	17,212	68,945	68,349	
17.	Depreciation	4,211	4,211	4,211	4,211	4,211	4,211	4,238	4,238	4,238	4,253	4,695	5,077	52,007
18.	Taxes on Income	273	273	273	273	273	273	532	532	532	532	532	527	4,821
19.	Ad Valorem Taxes	1,699	1,685	1,640	1,654	1,623	1,652	1,625	1,601	1,583	1,628	499	1,973	18,863
20.	Return	3,632	3,600	3,568	3,537	3,505	3,485	3,466	3,434	3,409	3,563	3,859	3,974	43,032
21.	Subtotal Revenue Requirement	9,815	9,769	9,693	9,674	9,612	9,621	9,861	9,805	9,762	9,976	9,584	11,551	118,722
22.	**III. O&M Expense Subaccount**													
23.	Fuel (ERRA)	4,522	(18)	(15)	(23)	(13)	(14)	40	-	-	-	-	177	4,657
24.	Fuel Carrying Costs (ERRA)	194	182	182	182	185	303	439	368	365	358	360	361	3,480
25.	Replacement Power (ERRA)	4,432	8,372	9,692	11,356	6,393	9,244	20,231	27,535	26,115	21,534	15,622	14,522	175,048
26.	Capacity Payments (ERRA)	-	1,657	2,692	1,434	4,588	4,384	3,748	4,310	4,047	3,674	903	1,704	33,141
27.	Foregone Sales Revenue (ERRA)	3,551	10,306	7,120	8,684	14,247	11,196	6,905	6,804	5,942	918	783	13,272	89,728
28.	Routine O&M	26,242	25,563	22,460	22,404	22,244	19,399	21,781	21,103	45,499	27,242	19,207	27,345	300,489
29.	Refueling (1 in 2012)	14,738	13,873	4,152	707	838	(91)	33	212	(142)	273	321	341	35,255
30.	Seismic Safety	11	145	338	370	100	148	198	471	257	314	267	642	3,261
31.	Investigation	-	4,534	11,951	12,614	3,982	7,212	-	22,327	4,438	-	-	-	67,059
32.	Repairs - After Outage	-	2,074	1,481	3,090	1,291	-	9,542	-	9,823	-	-	-	27,302
33.	Regulatory - After Outage	-	-	-	-	144	121	156	48	51	473	2,427	-	3,421
34.	Defueling	-	-	-	-	-	-	-	122	651	158	-	-	932
35.	Litigation	-	-	-	-	-	603	39	79	49	862	2,307	1,783	5,722
36.	Payroll Taxes	1,305	1,555	1,226	1,065	1,209	993	952	1,205	900	1,146	928	959	13,442
37.	Other (Pensions, PBOP, Insurance)	2,762	3,155	1,374	2,133	2,192	989	1,256	2,568	907	1,796	1,107	1,671	21,909

SOUTHERN CALIFORNIA EDISON COMPANY
SONGS 2&3 Outage Memorandum Account - February 2013
I.12-10-013
($000)

		2012												
		January	February	March	April	May	June	July	August	September	October	November	December	YTD
38.	Subtotal	57,757	71,398	62,655	64,015	57,399	54,489	65,320	87,151	98,902	58,750	44,231	62,777	784,845
39.	**IV. Huntington Beach Subaccount**	-	519	1,543	3,295	2,356	1,801	689	1,587	2,246	991	1,001	817	16,845
40.	**V. Demand Response Subaccount**	-	-	-	-	-	32	171	47	12	2,424	37	46	2,769
41.	**VI. Transmission Upgrades Subaccount**													
42.	Capital Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
43.	Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
44.	Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
45.	Taxes on Income	-	-	-	-	-	-	-	-	-	-	-	-	-
46.	Ad Valorem Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
47.	Return	-	-	-	-	-	-	-	-	-	-	-	-	-
48.	Subtotal Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-
49.	O&M (if any)	-	-	-	-	-	-	-	-	-	-	-	-	-
50.	**VII. Authorized Revenue Requirment Subaccount**													
	Monthly Revenue Requirement GRC	30,383	26,399	32,874	29,387	30,881	43,832	58,276	72,223	63,257	52,797	29,885	27,893	498,087
	Monthly Revenue Requirement SGR	7,030	6,108	7,606	6,799	7,145	10,141	13,483	16,710	14,635	12,215	6,914	6,453	115,239

NOTES:

1. All amounts shown above reflect SCE's 78.21% share
2. Severance costs (SCE Share) included in Line No. 28 reflect an accrued amount of $36.0 million, however only $13.8 million has been paid out as of December 31, 2012.
3. Received $45.4 million (100% share) from MHI and this amount is not included above.
4. The costs shown in the Demand Response subaccount also include other ISO market costs that were incurred as a result of the outages.
5. SCE is still in the process of identifying any Transmission upgrade costs incurred as a result of the outages. Any amounts will be included in the next reporting cycle.

(End of Appendix A)

Appendix B

San Diego Gas & Electric Company's Year End 2012 SONGSMA Report

SAN DIEGO GAS & ELECTRIC COMPANY
SONGS 2&3 Outage Memorandum Account
I.12-10-013
($000)

	2012												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1 I. Sunk Capital Cost Subaccount													
2 Capital Expenditures	3,322	10,392	2,468	1,795	2,167	3,864	3,281	1,994	1,996	2,818	2,138	2,241	38,475
3 CWIP	98,813	109,820	108,961	113,845	116,440	119,138	120,983	125,286	130,634	92,230	112,139	110,855	110,855
4 Rate Base	103,504	104,677	105,159	106,805	107,782	105,458	103,472	103,344	102,936	103,797	113,965	121,857	106,896
5 Depreciation	817	827	835	851	862	852	843	845	847	856	939	1,010	10,385
6 Taxes on Income	337	342	344	349	355	348	339	339	337	334	303	341	4,067
7 Ad Valorem Taxes	-	-	-	1,940	-	-	-	-	-	-	-	1,977	3,917
8 Return	725	733	736	748	755	738	724	723	721	727	798	853	8,979
9 Subtotal Revenue Requirement	1,879	1,902	1,914	3,887	1,971	1,939	1,907	1,908	1,905	1,917	2,040	4,181	27,348
10 II. Steam Gen Replacement/Removal Capital Cost Subaccount													
11 Capital Expenditures - Replace	61	(982)	440	5	77	802	1,076	(172)	(798)	(469)	12,577	248	12,863
12 Capital Expenditures - Remove	849	714	189	187	325	187	190	201	194	199	(12,420)	(134)	(9,320)
13 Rate Base - Replace	133,780	132,238	130,887	130,029	128,990	128,347	128,197	127,556	125,980	124,261	127,896	129,997	129,013
14 Rate Base - Remove	-	-	-	-	-	-	-	-	-	-	3,713	12,303	1,335
15 CWIP Balance - Replace	-	-	-	-	-	-	-	-	-	-	-	137	137
16 CWIP Balance - Remove	27,349	28,063	28,251	28,439	28,764	28,951	29,141	29,342	29,536	29,735	9,826	-	-
17 Depreciation	1,062	1,059	1,057	1,058	1,059	1,062	1,069	1,072	1,068	1,064	1,107	1,152	12,888
18 Taxes on Income	418	413	407	404	400	398	397	395	390	385	369	414	4,789
19 Ad Valorem Taxes	-	-	-	153	-	-	-	-	-	-	-	343	496
20 Return	937	926	916	910	903	898	897	893	882	870	921	996	10,949
21 Subtotal Revenue Requirement	2,417	2,397	2,380	2,526	2,362	2,358	2,363	2,360	2,341	2,318	2,397	2,905	29,123
22 III. O&M Expense Subaccount													
23 Fuel (ERRA)	1,228	(5)	(4)	(6)	(3)	(3)	(4)	(4)	24	-	-	-	1,223
24 Fuel Carrying Costs (ERRA)	10	10	12	13	14	16	20	20	21	19	18	19	192
25 Replacement Power (ERRA)	(5,312)	3,236	4,814	5,333	6,457	5,859	7,618	8,082	8,992	9,849	8,623	8,698	72,249
26 Capacity Payments (ERRA)	6	205	116	411	279	381	378	560	579				2,916
27 Foregone Sales Revenue (ERRA)							206	206	206	46	46	46	756
28 Routine O&M	6,255	7,054	5,914	5,890	6,044	5,099	5,698	5,519	6,402	7,460	5,079	7,145	73,559
29 Refueling (1 in 2012)	3,513	3,828	1,093	186	228	(24)	9	55	(20)	75	85	89	9,116
30 Seismic Safety	3	40	89	97	27	39	52	124	37	87	71	168	832
31 Investigation	-	1,251	3,147	3,317	1,082	1,896	-	5,839	625	-	-	-	17,155
32 Repairs - After Outage	-	572	390	812	351	-	2,496	-	1,382	-	-	-	6,004
33 Regulatory - After Outage	-	-	-	-	39	32	41	13	7	130	642	-	903
34 Defueling	-	-	-	-	-	-	-	32	92	43	-	-	167
35 Litigation	-	-	-	-	-	-	-	-	-	-	-	-	-
36 Payroll Taxes	350	423	347	287	319	292	256	337	242	301	265	324	3,744
37 Other (Pensions, PBOP, Insurance)	2,732	3,197	2,774	2,620	2,850	2,551	2,287	3,092	2,239	2,729	2,302	2,253	31,624
38 Subtotal	8,785	19,811	18,693	18,960	17,687	16,139	19,056	23,874	20,826	20,738	17,130	18,741	220,440
39 IV. Huntington Beach Subaccount	-	-	-	-	-	-	-	-	-	-	-	-	-
40 V. Demand Response Subaccount													
41 Peak Time Rebate - Small Commercial (PTRA)	-	-	-	-	-	-	-	-	-	-	-	-	-
42 Demand Bidding Program (DBP 2012)	-	-	-	-	-	-	-	-	-	-	-	-	-

SAN DIEGO GAS & ELECTRIC COMPANY
SONGS 2&3 Outage Memorandum Account
I.12-10-013
($000)

	2012												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
43 Marketing, Education & Outreach (ME&O)	-	-	-	-	1	-	0	1	38	45	5	3	91
44 Subtotal DR	-	-	-	-	1	-	0	1	38	45	5	3	91
45 VI. Transmission Upgrades Subaccount													
46 Capital Expenditures	-	-	-	-	-	(8)	9	93	1,245	137	653	883	3,013
47 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
48 Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
49 Taxes on Income	-	-	-	-	-	-	-	-	-	-	-	-	-
50 Ad Valorem Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
51 Return	-	-	-	-	-	-	-	-	-	-	-	-	-
52 Subtotal Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-
53 O&M (if any)	-	-	-	-	-	-	-	-	-	-	-	-	-
54 VII. Authorized Revenue Requirement Subaccount													
55 Monthly Revenue Requirements	16	16	16	16	16	16	16	16	16	16	16	15	185
56 VIII. Adders to SCE-Originated SONGS Costs													
57 SCE-Billed Costs Not Included by SCE in § III	(12)	3,762	(73)	(101)	(18)	(46)	(39)	(128)	(33)	(46)	106	902	4,274
58 SDG&E Portion of Nuclear and Related Insurance	-	-	956	-	463	-	-	945	-	-	-	-	2,364
59 SDG&E Portion of SONGS Site Easement	-	-	-	20	-	-	-	-	-	-	-	-	20
60 SDG&E Overheads on SONGS Costs - Capital (Adder to § I)	786	964	628	889	574	775	886	958	1,003	1,069	773	678	9,983
61 SDG&E Overheads on SONGS Costs - O&M (Adder to § III)	624	526	550	1,057	661	735	860	723	679	1,197	930	974	9,515
62 Net Impact of Billing Lag (Temporary Adder to §§ I & III)	2,038	(9,161)	(5,575)	10,830	675	491	(637)	(3,352)	1,222	5,777	(1,375)	(4,416)	(3,484)
63 IX. SDG&E Direct Cost of SONGS Oversight													
64 Operational and Financial Oversight Team	45	90	62	40	69	43	56	54	51	60	40	59	668

NOTES
All amounts shown reflect SDG&E's actual costs for SONGS, including 20% share of SONGS 100%-level costs incurred by SCE plus contractual overheads.
SGRP costs reported net of 20% of estimated removal and disposal costs for the original steam generators granted in SDG&E's 2006 SGRP Decision D.06-11-026.
SCE advance bills SDG&E for the month and trues-up previous advance bills. The "Lag Adjustment" converts SONGS data for the billing process to match actual SDG&E posting periods.
SCE 's invoices to SDG&E do not allow O&M costs to be broken out into the cost categories shown for O&M. Figures were provided by SCE, who allocated the SDG&E prorated billing based upon SCE's reported costs.
SDG&E has not yet received a 2012 GRC decision authorizing a revenue requirement. Revenue Requirement based on AL 2302-E filed November 10, 2011, pending a final GRC decision.
SDG&E's SONGS Oversight includes estimated overheads for Payroll Tax, Incentive Compensation Plan ("ICP"), Pension & Benefits, Workers' Compensation, Vacation & Sick Leave, PLPD Insurance, and Purchasing.
Property tax amounts are estimated based on an allocation of total property taxes paid.
Replacement Power (ERRA) amount estimated for 2012 excludes lost generation replacement costs for planned refueling and maintenance outage for 01/10/12 through 03/05/12 for SONGS Unit 2 of $5,039K.
Capacity Payments (ERRA) amount estimated for CPM charges and Resource Adequacy (RA) purchases.

SAN DIEGO GAS & ELECTRIC COMPANY
SONGS 2&3 Outage Memorandum Account
I.12-10-013
($000)

SONGS COSTS BY AUTHORIZATION CATEGORY

		As Reported	SCE GRC D.12-11-051	SDG&E GRC Pending	SGRP D.05-12-040	ERRA D.12-07-006 D.12-08-007 D.12-12-022	Other BA- DR Resolutions E-4502, E-4511, D. 12-14-045	Other BA - NGBA AL-2302	Transmission Owner Tariff	NEW
1	**I. Sunk Capital Cost Subaccount**									
2	Capital Expenditures	38,474.9	$39,250.80	$10,009.60						
3	CWIP	110,854.7	110,854.7							
4	Rate Base	106,896.3	106,896.3							
5	Depreciation	10,384.7	10,384.7							
6	Taxes on Income	4,067.4	4,067.4							
7	Ad Valorem Taxes	3,916.9	3,916.9							
8	Return	8,979.3	8,979.3							
9	Subtotal Revenue Requirement	27,348.3								
10	**II. Steam Gen Replacement/Removal Capital Cost Subaccount**									
11	Capital Expenditures - Replace	12,863.2			12,863.2					
12	Capital Expenditures - Remove	(9,319.5)			(9,319.5)					
13	Rate Base - Replace	129,013.2			129,013.2					
14	Rate Base - Remove	1,334.6			1,334.6					
15	CWIP Balance - Replace	136.6			136.6					
16	CWIP Balance - Remove	-			-					
17	Depreciation	12,888.0			12,888.0					
18	Taxes on Income	4,789.4			4,789.4					
19	Ad Valorem Taxes	495.9			495.9					
20	Return	10,949.3			10,949.3					
21	Subtotal Revenue Requirement	29,122.6								
22	**III. O&M Expense Subaccount**									
23	Fuel (ERRA)	1,223.0				1,223.0				
24	Fuel Carrying Costs (ERRA)	192.0				192.0				
25	Replacement Power (ERRA)	72,249.2				72,249.2				
26	Capacity Payments (ERRA)	2,915.9				2,915.9				
27	Foregone Sales Revenue (ERRA)	755.7				755.7				
28	Routine O&M	73,558.7	73,558.7							
29	Refueling (1 in 2012)	9,116.4	9,116.4							
30	Seismic Safety	831.8	831.8							
31	Investigation	17,155.3								17,155.3
32	Repairs - After Outage	6,004.2								6,004.2
33	Regulatory - After Outage	902.9								902.9
34	Defueling	166.9								166.9
35	Litigation	-								-
36	Payroll Taxes	3,744.1	3,744.1							
37	Other (Pensions, PBOP, Insurance)	31,623.9	31,623.9							
38	Subtotal	220,440.0								
39	**IV. Huntington Beach Subaccount**	-								

		As Reported	SCE GRC D.12-11-051	SDG&E GRC Pending	SGRP D.05-12-040	ERRA D.12-07-006 D.12-08-007 D.12-12-022	Other BA- DR Resolutions E-4502, E-4511, D. 12-14-045	Other BA - NGBA AL-2302	Transmission Owner Tariff	NEW
40	V. Demand Response Subaccount									
41	Peak Time Rebate - Small Commercial (PTRA)	-					-			
42	Demand Bidding Program (DBP 2012)	-					-			
43	Marketing, Education & Outreach (ME&O)	90.6					90.6			
44	Subtotal DR	90.6								
45	VI. Transmission Upgrades Subaccount									
46	Capital Expenditures	3,012.5							3,012.5	
47	Rate Base	-							-	
48	Depreciation	-							-	
49	Taxes on Income	-							-	
50	Ad Valorem Taxes	-							-	
51	Return	-							-	
52	Subtotal Revenue Requirement	-								
53	O&M (if any)	-							-	
54	VII. Authorized Revenue Requirement Subaccount									
55	Monthly Revenue Requirements	185.4						185.4		
56	VIII. Adders to SCE-Originated SONGS Costs									
57	SCE-Billed Costs Not Included by SCE in § III	4,274.3	4,274.3							
58	SDG&E Portion of Nuclear and Related Insurance	2,363.9		2,363.9						
59	SDG&E Portion of SONGS Site Easement	20.1		20.1						
60	SDG&E Overheads on SONGS Costs - Capital (Adder to § I)	9,983.2		9,983.2						
61	SDG&E Overheads on SONGS Costs - O&M (Adder to § III)	9,515.2		9,515.2						
62	Net Impact of Billing Lag (Temporary Adder to §§ I & III)	(3,484.4)	(3,484.4)							
63	IX. SDG&E Direct Cost of SONGS Oversight									
64	Operational and Financial Oversight Team	668.3		668.3						

NOTES

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SDG&E's SONGS Oversight includes estimated overheads for Payroll Tax, Incentive Compensation Plan ("ICP"), Pension & Benefits, Workers' Compensation, Vacation & Sick Leave, PLPD Insurance, and Purchasing.
Property tax amounts are estimated based on an allocation of total property taxes paid.
Replacement Power (ERRA) amount estimated for 2012 excludes lost generation replacement costs for planned refueling and maintenance outage for 01/10/12 through 03/05/12 for SONGS Unit 2 of $5,039K.
Capacity Payments (ERRA) amount estimated for CPM charges and Resource Adequacy (RA) purchases.
Sunk capital line items 3-8 include SDG&E overheads and AFUDC

(End of Appendix B)

Appendix C

Timeline

Appendix C - Timeline

1/9/2012	U2 Cycle 17 (C17) refueling outage (RFO) started 60-day schedule
1/272012	U2 Fuel moved to fuel pool complete
1/31/2012	U3 leak identified
2/5/2012	U2 steam generator retainer bar problem identified
2/8/2012	SCE begins Root Cause Analysis (U3)
2/11/2012	U2 initial Eddy Current Testing (ECT) completed
2/12/2012	U3 ECT inspection locates leaking tube
2/14/2012	U2 Expanded ECT (based on U3 findings)completed
2/14/2012	U2 replace Emergency Core Cooling System mini flow piping project completed
3/1/2012	U2 fuel move from fuel pool to core completed
3/1/2012	SCE Board of Directors (BoD) meeting; Dietrich reports delay restart U2 until source of U3 tube leak known
3/2/2012	U2 High pressure Turbine retrofit project completed
3/4/2012	U2 Replacement Reactor Vessel head project completed
3/4/2012	U2 C17 RFO originally scheduled to end (Return to Service -RTS)
3/13/2012	U2 C17 RTS restart schedule change from 3/20 to 4/15 due to additional ECT
3/13/2012	U3 In-situ pressure test of 129 tubes; 8 tubes fail
3/14/2012	U2 C17 RFO restart schedule changed from 4/15 to 5/16
3/16/2012	U2 equipment hatch closed
3/19/2012	NRC onsite Augmented Inspection Team (AIT) begins ten days of inspections
3/23/2012	SCE submits Steam Generator Return-to-Service Action Plan to NRC
3/27//2012	Confirmatory Action Letter issued by NRC
3/27//2012	U2 C17 RFO restart schedule changed from 5/16 to 6/1
3/2012	SCE developed plan to postpone, cancel, and re-schedule capital projects
4/1/2012	U2 FAC project completed
4/2/2012	U2 RTS scheduled
4/3/2012	U2 equipment hatch opened
4/6/2012	U2 special interest ECT
4/10/2012	U2 Tube-to-Tube wear (TTW) discovered
4/15/2012	U3 initial ECT completed
4/20/2012	U2 TTW inspection letter to NRC
4/23/2012	U2 first tube wear Root Cause Analysis (RCA) issued by SCE
4/23/2012	U2 Emergency Diesel generator replacement project completed
4/24/2012	U2 tube plugging and stabilizing list issued
4/26/2012	SCE BoD meeting with update on SONGS: Fluid Elastic Instability cause of TTW; reports U2 restart on 6/1/12; U3 by 6/30/12
5/7/2012	U3 first tube wear RCA issued by SCE, finds TTW in U2
5/72012	U2 C17 RFO restart schedule changed from 6/1 to 7/1

5/7/2012	NRC Restart statement issued
5/16/2012	NRC issued AIT Charter rev.1
6/2012	U3 planning begins to place U3 into preservation mode
6/7/2012	U2 C17 RFO restart schedule changed from 7/1 to 8/17
6/18/2012	NRC public meeting in San Juan Capistrano (AIT Exit)
6/25/2012	Budget Review Committee meeting to defer capital projects (part 1 of 2)
7/2012	Efforts to place U3 into preservation mode begin
7/1/2012	U2 Vibration and Loose Parts Monitoring System replacement project completed
7/11/2012	Budget Review Committee meeting to defer capital projects (part 2 of 2)
7/18/2012	NRC issues initial AIT report
7/19/2012	U2 C17 RFO restart schedule changed from 8/17 to 11/18
7/27/2012	SCE separates outage response team into U2 Restart and U2/U3 long-term repair teams; SCE tells MHI of expectations of warranty conditions for long-term repair
8/23/2012	U2 C17 RFO restart schedule changed from 11/18 to 12/2
8/22/2012	NRC performs follow-up steam generator AIT inspection
8/25/2012	SCE BoD meeting with SONGS update:
9/4/2012	NRC adopted modified inspection plans for U2/U3 based on "extended Outage Shutdown Condition"
9/6/2012	SCE BoD meeting with SONGS update: status of SONGS as of 8/27 target U2 restart 12/12, U3 4Q2013
9/11/2012	U3 major systems engineering recommendations completed re long-term lay-up plan, reviews on-going; SCE-25
9/24/2012	NRC meets with Mitsubishi Heavy Industries (MHI) in Kobe, Japan
9/28/2012	NRC follow-up inspection of unresolved issues from AIT report
10/2012	SONGS-wide meeting re more inspections(TR 1056)
10/1/2012	U3 reactor defueling begins
10/3/2012	U2 CAL response submitted to the NRC re U2 restart plan
10/5/2012	U3 reactor defueling ends
10/9/2012	NRC public meeting at Dana Point
10/11/2012	MHI reps meet with Avella and Dietrich and proposed repair/replacement options; assessment expected by 2Q13 or 3Q13
10/17/2012	U2 equipment hatch closed
10/20/2012	U2 achieves Mode 4 to test systems
10/23/2012	U2 achieves Mode 3 (raised reactor coolant system to normal operating pressure and temperature to test return-to-service readiness)
10/25/2012	U2 Reactor Coolant System test at normal operating conditions (reactor not critical)
10/25/2012	SCE BoD meeting SONGS status: U2 response to CAL filed with NRC, restart discussions underway; U3 long-term repair plans in development
10/26/2012	U2 entered Mode 4
10/27/2012	U2 returned to Mode 5
11/8/2012	U2 C17 RFO restart schedule changed from 12/2 to 2/3/13

11/8/2012	E. Avella (SCE) Letter to Dr. A. Kaguchi: provides MHI with SCE's acceptable warranty conditions for long-term repair of the SGs; given in meetings since 7/27/2012; SCE-24
11/9/2012	AIT Follow-up Report : two unresolved issues from CAL; advised no reply to SCE's CAL response until inspections, technical review, public meetings, + 45 days of process time before earliest U2 restart
11/13/2012	Letter from Edward Avella to MHI Regarding Screening Criteria for Acceptance of Steam Generator Permanent Repair (SCE-20)
11/20/2012	SCE submits 1st Proof of Loss to NEAL under outage accident insurance policy (replacement power)
11/28/2012	Letter from P. Dietrich to K. Yamauchi at MHI: MHI hasn't complied with contract to provide repairs or replacements with due diligence; wants repair options for U2 and U3 by 12/28; (SCE-21)
11/30/2012	NRC public Meeting in Laguna Hills
12/3/2012	NRC conducts follow-up inspections to SCE's CAL response
12/5/2012	NRC's Atomic Safety Licensing Board held hearings to determine whether SCE needs a license amendment to restart U2 at 70%
12/13/2012	U2 C17 restart schedule changed from 2/2/13 to 3/3/2013
12/14/2012	MHI progress letters (2) to SCE on long-term repair options (Exhibits SCE-14, SCE-17)
12/14/2012	SCE submits 2nd Proof of Loss to NEAL
12/14/2012	MHI/SCE meeting for status on repair options; SCE-22
12/18/2012	NRC public meeting on requests for Additional Information (RAIs) in Washington D.C.
12/19/2012	Letter from P. Dietrich to K. Yamauchi at MHI: contract requires actual repair or replacement to occur with due diligence and dispatch; SCE-23
12/19/2012	Letter from E. Avella (SCE) to Dr. H. Kaguchi at SONGS SG Repair Site Team: follow-up to 12/14 meeting, MHI should provide 3 options, following SCE review criteria—MHI missed two prior dates for final recs
12/20/2012	MHI provided long-term repair options and recommendations (SCE-15)
12/20/2012	SCE submits 3rd Proof of Loss to NEAL; total of claims is $234 million (100%), $183 million (SCE share)
12/26/2012	NRC request for additional information in response to CAL
12/29/2012	MHI Letter to SCE
2013	
1/30/2013	U3 Long term preservation Plan Rev. 8; SCE-25

(End of Appendix C)

Appendix D

O&M by Functional Group

Appendix D – O&M by Functional Group

Functional Group		Preliminarily Allowed	Total Base Recorded	Recorded Base-Routine	Difference between Preliminarily Allowed and Recorded Base-Routine	SCE Claimed Exempt[1] ($ / %)	Comments
		All values in 1000s of 2012$, 100% Share					
Operations	Labor	$31,654	$39,437	$34,373	$(2,719)	$10,657 / 30%	Responsible for operation of SONGS, including safety systems, in normal or shutdown conditions.
	Non-Labor	$3,704	$1,385	$1,385	$2,319		
	Total	$35,358	$40,822	$35,758	$(400)		
Maintenance	Labor	$64,401	$52,518	$51,409	$12,992	$33,025 / 30%	Performs preventive and corrective maintenance and testing of mechanical, electrical, control, and protective systems.
	Non-Labor	$45,584	$36,745	$36,745	$8,839		
	Total	$109,985	$89,263	$88,154	$21,831		
Engineering	Labor	$41,984	$40,049	$37,758	$4,226	$7,923 / 15%	Of the five divisions within this group, SCE asserts that three divisions (Plant Engineering, Nuclear Safety, and Nuclear Oversight/Assessment) are essential during shutdown.
	Non-Labor	$10,653	$(1,257)	$(1,257)	$11,910		
	Total	$52,637	$38,792	$36,502	$16,136		
Site Projects	Labor	$852	$657	$657	$196	$0 / 0%	Performs cyclical or reactive projects. SCE does not contend that expenses in this group would be necessary under extended shutdown conditions.
	Non-Labor	$14,876	$16,896	$16,896	$(2,020)		
	Total	$15,728	$17,553	$17,553	$(1,825)		
Rad Chemical	Labor	$15,770	$12,835	$11,828	$3,942	$7,238 /	Responsible for chemistry control of

[1] Converted from 2009$ as shown in Table V-4 of SCE-1 by multiplying by 1.095

Functional Group		Preliminarily Allowed	Total Base Recorded	Recorded Base-Routine	Difference between Preliminarily Allowed and Recorded Base-Routine	SCE Claimed Exempt[1] ($ / %)	Comments
Control	Non-Labor	$8,314	$7,624	$7,624	$690	30%	fuel pools and effluent as well as radioactive material control.
	Total	$24,084	$20,459	$19,452	$4,632		
Regulatory Affairs	Labor	$8,917	$9,316	$9,112	$(195)	$9,591 / 75%	Includes emergency preparedness and occupational safety and health.
	Non-Labor	$3,843	$1,714	$1,714	$2,129		
	Total	$12,760	$11,030	$10,825	$1,935		
Security	Labor	$39,870	$41,601	$41,326	$(1,456)	$37,357 / 90%	Protection against radiological sabotage per NRC regulations.
	Non-Labor	$1,410	$2,112	$2,112	$(702)		
	Total	$41,280	$43,713	$43,438	$(2,158)		
Training	Labor	$10,670	$10,963	$10,942	$(272)	$4,427 / 30%	Trains operations, maintenance, and other staff.
	Non-Labor	$4,049	$2,619	$2,619	$1,430		
	Total	$4,719	$13,582	$13,561	$1,158		
Nuclear Support	Labor	$31,239	$30,646	$29,762	$1,477	$17,879 / 20%	Implements financial planning, budgeting, accounting, and compliance programs.
	Non-Labor	$58,328	$52,743	$52,743	$5,585		
	Total	$89,567	$83,389	$82,506	$7,061		
Corporate Support	Labor	$(10,688)	$0	$0	$(10,688)	n/a	
	Non-Labor	$(7,032)	$(20,463)	$(20,463)	$13,431		
	Total	$(17,720)	$(20,463)	$(20,463)	$2,743		
Total	Labor	$234,669	$238,021	$227,165	$7,504	$128,096 / 32%	
	Non-Labor	$143,729	$100,118	$100,118	$43,611		
	Total	$378,398	$338,139	$327,284	$51,114		

(End of Appendix D)

Appendix E

SONGS 2012 Base O&M Costs Excluding Corporate Support, Severance, and IT (100% share, 000's of 2012$

Appendix E – SONGS 2012 Base O&M Costs, excluding Corporate Support, Severance, and IT (100% share, 000's of 2012$)

Month	Base - Routine				SGIR (includes both "Base" and "Total" SGIR)				Total Adopted Base O&M
	Recorded[1]	Adjustment Factor	Adopted	Disallowed	Recorded[2]	Adjustment Factor	Adopted as Base O&M	To Review in Phase 3[3]	
January	35,354	1.0	35,354	0	0	1.0	0	0	35,354
February	33,788	1.0	33,788	0	9,246	1.0	9,246	0	43,034
March	29,112	1.0	29,112	0	18,214	0.5	9,107	9,107	38,219
April	29,556	1.0	29,556	0	20,970	0.0	0	20,970	29,556
May	29,135	1.0	29,135	0	7,832	0.0	0	7,832	29,135
June	25,770	0.9	23,193	2,577	10,092	0.0	0	10,092	23,193
July	28,294	0.8	22,635	5,659	13,603	0.0	0	13,603	22,635
August	27,222	0.7	19,055	8,167	30,171	0.0	0	30,171	19,055
September	23,483	0.6	14,090	9,393	20,471	0.0	0	20,471	14,090
October	35,353	0.5	17,677	17,677	2,007	0.0	0	2,007	17,677
November	25,515	0.4	10,206	15,309	3,794	0.0	0	3,794	10,206
December	25,164	0.4	10,066	15,098	4,556	0.0	0	4,556	10,066
Total	347,746	n/a	273,867	73,880	140,956	n/a	18,353	122,603	292,220

(End of Appendix E)

[1] SCE-35 at 6.

[2] Ibid. Sum of lines: "Total Base – SGIR Recorded" and "Total SG Insp & Repair Recorded."

[3] If, in Phase 3, SCE is found to have been imprudent or otherwise at fault, these SGIR costs may be subject to refund.

Appendix F

Capital Expenditures

Appendix F – Capital Expenditures

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
Common - Required	Total	$38,389	Includes projects that are not unique to a single reactor unit.
	Spare Parts Blanket	$4,182	Includes long lead time items needed for continuity of service that are not typically used more than once a year.
	Outage Replacements - overhauls to SONGS 2C17 Allowance	$5,377	Replacements of in-kind capital equipment during the U2 Refueling Outage (RFO)
	U2/3 ISFSI AHSMs	$4,819	New Advanced Horizontal Storage Modules (AHSMs) are added to the Independent Spent Fuel Storage Installation (ISFSI) for each refueling. The AHSMs protect the fuel canisters and provide radiation protection.
	SCR 32PTH System - Canister	$5,223	This project is an upgrade of the dry storage fuel canisters to hold more fuel per canister. The project also includes purchase of related equipment.
	U2/3 Dry Cask Spent Fuel Storage - Canisters	$11,281	Transfer of fuel from the ISFSI to dry storage for the U2 RFO and U3 defueling.
	Other (furniture, computers, tools, transfer of fuel to ISFSI)	$7,507	
Work in Progress	Total	$84,533	Includes projects that were in process during 2011.
	Control Room Upgrade	$3,545	Changes to the Control Room to meet industry standards and NRC expectations.
	Eddy Current Testing U2C17	$3,851	The NRC requires a full length examination of each steam generator tube after the first cycle of operation.
	CCW Heat Exchangers SONGS 2	$5,017	The Component Cooling Water (CCW) heat exchangers for U2 were replaced during the RFO.

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
	U2 High Pressure Turbine (HPT) Retrofit	$7,075	The U2 HPT was replaced during the RFO. This project was approved by the CPUC in SCE's 2009 GRC, D.09-03-025.
	Replace 400' of U2 ECCS Schedule 10 Mini Flow Piping	$7,629	During the U2 Cycle 16 RFO, evidence of damage to the Emergency Core Cooling Schedule (ECCS) 10 piping was discovered. During the U2 Cycle 17 RFO in 2012, the highest risk sections of piping were replaced.
	FAC - Capital R2C17	$7,658	This is part of a long-term project to replace piping components subject to Flow Accelerated Corrosion (FAC). The costs shown here were incurred during the U2 Cycle 17 RFO. Replacements for U3 were rescheduled.
	U2 Rapid Refueling	$10,840	Completed during the U2 Cycle 17 RFO, this project was designed to allow faster assembly and disassembly of the Reactor Vessel Heads (RVH).
	U2 Procure & Install RRVH Heads	$29,069	Replacement of the RVH during the U2 Cycle 17 RFO.
	Other (Tech Specs, various capital replacements)	$9,849	
Emergent - Regulatory Required	Total	$17,937	Projects that emerged after SCE's 2012 GRC forecast due to regulatory requirements.
	Cyber Security Phase 2	$3,576	Phase 2 (of 3) of an NRC-required project to implement a cyber security defense strategy.
	NFPA-805 Fire	$4,494	An ongoing project to meet NRC fire protection requirements that apply regardless of the operational status of the plant.
	Other (upgrades related to Once Through Cooling environmental, Fukushima	$9,867	

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
	responses, and security)		
Rescheduled	Total	$1,434	Projects that were started in 2012, but rescheduled or suspended after the outage began.
Ongoing - Completion Rescheduled	Total	$19,754	Projects started before 2012, but rescheduled or suspended due to the outages. Includes some projects for U3 that are analogous to U2 projects described in the "Works in Progress" category.
	U3 HPT Retrofit Project	$8,963	Analogous to the U2 project above, but not completed.
	Other (CCW Heat Exchangers, Rapid Refueling and RVHs, U2 water purification)	$10,791	
Marine Mitigation	Total	$5,559	Ongoing projects to comply with SONGS's permit from the California Coastal Commission.
	Reef	$1,388	Costs associated with Coastal Commission monitoring of the completed reef.
	Wetlands	$4,171	Monitoring of the restored wetlands and corrective construction.
Grand Total		**$167,606**	

(End of Appendix F)

Appendix G

Results of Operations Model Output From SCE's GRC

Appendix G – Results of Operations Model Output, from SCE's 2012 GRC

Line	Item	Adopted (1000s of dollars)	
1.	**TOTAL OPERATING REVENUES**	5,596,526	
2.	**OPERATING EXPENSES:**		
3.	Production		
4.	Steam	14,478	
5.	Nuclear	298,447	
6.	Hydro	56,000	
7.	Other	126,328	
8.	Subtotal Production	495,253	
9.	Transmission	87,740	
10.	Distribution	465,850	
11.	Customer Accounts	209,595	
12.	Uncollectibles	11,062	
13.	Customer Service & Information	45,521	
14.	Administrative & General	818,289	
15.	Franchise Requirements	49,381	
16.	Revenue Credits	(149,965)	
17.	Subtotal	2,032,725	
17.	Escalation	168,852	
18.	Depreciation	1,221,584	
19.	Taxes Other Than On Income	245,929	
20.	Taxes Based On Income	463,520	
21.	Total Taxes	709,449	
22.	**TOTAL OPERATING EXPENSES**	4,132,609	
23.	**NET OPERATING REVENUE**	1,316,581	
24.	**RATE BASE**	15,063,859	
25.	**RATE OF RETURN**		8.74%
26.	Four Corners	88,388	
27.	Mohave	(5,552)	
28.	Legacy Meters	64,500	
29.	**REVENUES AT PRESENT RATES**	5,398,840	
30.	**NET INCREASE OVER PRESENT RATES**		197,686

(End of Appendix G)

BRIEFING ON SAN ONFRE NUCLEAR GENERATING STATION OII
PHASE 1 AND PHASE 1A DECISION
(from ALJs Darling and Dudney)

- The Phase 1/1A decision adopts interim rate reductions for Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) ratepayers as a result of reduced operating costs in 2012 following a Unit 3 steam generator tube leak at San Onofre Nuclear Generating Station (SONGS) on January 31, 2012 and an immediate halt to generation.

- The decision orders refunds of approximately $94 million ($74.2 million SCE; $19.3 million SDG&E) applicable only to the 2012 revenue requirement.

- The U.S. Nuclear Regulatory Commission (NRC) found that SCE appropriately responded to the tube leak by shutting down Unit 3, and took reasonable steps to investigate the steam generator problems and to mitigate some costs. However, as the year progressed, we found SCE to be single-minded about its restart plan, and slow to understand the technical challenges and regulatory timeframe required to implement it.

- The decision establishes a timeline of significant events and imputes to SCE what it knew or should have known about the status of both units during 2012.

- In January and February, SCE was conducting a scheduled refueling outage (RFO) on Unit 2; Unit 2 did not return to service. Prior to March 15, SCE acted as a reasonable operator to complete the RFO, and try to determine the causes and extent of the damage to both Unit 2 and Unit 3. These costs are recoverable.

- As of March 15, SCE knew that Unit 3 had an unknown type of tube wear which led to the leak, and Unit 2 was of similar design. On March 27, 2012, the NRC prohibited any restart until numerous conditions were met, and cleared by the NRC. By May 7, 2013, SCE knew that both Unit2 and Unit 3 had the unknown Tube-to-Tube wear phenomena and that repair options were undeveloped.

- The Commission finds SCE's decisions after May 2012 to apply resources to a restart plan was the result of an unsound decisionmaking process, primarily because SCE did not consider cost or other options, or realistically assess the regulatory hurdles blocking a reasonably foreseeable restart. Therefore, the decision adopts interim rate reductions using a gradual percentage disallowance of O&M beginning in June 2012, and continuing through the end of 2012.

- SONGS-related O&M is separated into "Base (routine)" and Steam Generator Inspection and Repair (SGIR) costs resulting from the outages. About 21% of Base O&M was disallowed in this decision. SGIR costs are not allowed, but will be considered in the context of all costs of the Steam Generator Replacement Project in Phase 3.

- About 80% of recorded 2012 capital expenditures are found to be reasonable, including those necessary to maintain the plant in safe condition, compliant with all applicable regulations.
- Recorded capital-related costs exceeded GRC estimates for both utilities. We reduced capital additions by 20% to remove unnecessary additions, but reductions to rate base result in an increase to rates, due to effects of the Tax Relief Act of 2010 that provided bonus depreciation for some assets recorded in 2012.
- The decision adopts a method for calculating the cost of replacement power in 2012, recovery of replacement power costs will be determined in Phase 3.
- The 2012 rate adjustments and the resulting 2012 revenue requirement reduction are summarized below:

Summary of Adopted Ratemaking			
100% share, 000s of 2012$			
Cost Category	**Adopted**	**Refund in 2014 Rates**	**Review in Phase 3**
Base O&M	$273,867	$73,880	
SGIR O&M	$18,353		$122,603
Other O&M (Corp. Support, IT, Severance)	$1,663	$4,527	
Subtotal	$293,883	$78,407	$122,603
RFO O&M	$45,077		
Seismic	$4,077		
Capital Expenditures	$134,080		
Capital Additions	($33,520)	($500)	
Replacement Power			To be calculated
2012 Revenue Requirement due to O&M and Capital Adjustments		($93,522) SCE: ($74,222) SDG&E: ($19,300)	

- The Utilities are ordered to make the refunds through each utility's established base rate balancing mechanism, effective on January 1, 2014. For SGIR costs already recovered in rates, the funds shall be separately accounted for and interest accrued at the one-year Treasury rate for the benefit of ratepayers in the event the Commission later finds these revenues should also be refunded.

SONGS PD – Comments Summary

Proceeding I.12-10-013

(prepared by Charlyn Hook)

SCE

Legal issue raised by other parties: SCE says Commission should use the preponderance of evidence standard (which just means more likely than not), not a higher "clear and convincing evidence" standard as some parties (ORA and World Business Academy) have argued.

SCE says that it wasn't clear that Unit 2 was going to have the same TTW problems as Unit 3 until April and May, when more sensitive testing was done. So we cannot impute knowledge to them back in March 2012.

SCE argues parties incorrect in arguing that there should be no costs allowed for Unit 2 because a) it was reasonably pursuing the 70% restart plan for Unit 2, and b) even if it had put Unit 2 in preservation mode sooner, it still would have been required to maintain a certain level of staffing for safety and general NRC requirements, thus they argue there is no evidence that they could have saved costs. SCE maintains the record needs to be re-opened to look at this issue more.

SCE argues that labor related A&G (benefits, incentive compensation) is reflected in the PD's disallowance of some O&M costs. SCE disagrees with ORA's argument that the disallowance should be even greater, because non-labor related A&G costs should be added into the disallowance, as these costs could not have been avoided even if SCE had reduced staffing at SONGS.

SCE disputes A4NR's allegation that SCE did not produce all correspondence between SCE and Mitsubishi; SCE says it produced some correspondence and never claimed it produced all communications.

SDG&E

SDG&E argues that on the one hand, the PD states that there has been no finding of imprudence, but yet also states that SCE's decision to pursue the restart of Unit 2 was the product of unsound decisionmaking and imputes (a share) of this to SDG&E. SDG&E argues that this may prejudge the outcome of some Phase 3 issues.

SDG&E is arguing that it should not be allocated its share of the disallowance, now, and that this should be deferred until Phase 3.

Supports preponderance of evidence standard.

PD need to clarify the derivation of the 20% reduction, and that it reflects only "capital spent in 2012 after May 7, 2013, that actually closed to ratebase in 2012."

TURN

TURN largely supports the PD and finds the May 7th date as the date to begin O&M reductions to be reasonable.

With respect to the Steam Generator Inspection and Repair (SGIR), the PD defers consideration of the reasonableness of these costs to Phase 3. The PD states that "we have made no finding that SCE was at fault or imprudently managed the steam generator replacement project, or unreasonably incurred the incremental SGIR costs in 2012." (PD p. 50) and orders SCE and SDG&E to "cease collection of these incremental costs" in rates. (PD p. 5) TURN questions what incremental costs are being incurred, and argues that all 2012 SGIR expenditures should be credited to ratepayers as an offset in 2014 rates. If Phase 3 concludes that these costs are reasonable, SCE and SDG&E can seek rate recovery.

Phase 3 scope/clarification: TURN recommends that the PD should clarify that if SCE is found to have imprudently managed the SGRP, costs should be disallowed in the Phase 3. TURN also concerned about statements in the PD to the effect that SCE can be found imprudent for SGIR costs if they had pre-existing knowledge of the risks of failure; they think this is too limiting.

TURN questions statement in the PD that the SGRP costs are presumed reasonable if under the original forecast in D.05-12-040.

Construction Work in Progress (CWIP): The PD should not prejudge the issue of whether accrued AFUDC for SONGS related CWIP can be capitalized or recovered. This is a Phase 2 issue, but TURN doesn't want it pre-judged in this PD and recommends a few modifications to the PD.

Replacement Power Cost Calculation: Supports the definition of replacement power costs in the PD. Supports the PD's direction to the utilities to recalculate the costs based on different indexes for replacement energy and forgone sales, and urges that the PD clarify that IOUs must use hourly DLAP prices, and make no other changes to this section.

ORA

The PD's findings are supported by a complete record, case doesn't need to be reopened. This will just delay the refund to ratepayers. O&M cost reductions should begin as of March 15, 2012, and the record supports this conclusion.

Disagrees with SCE's argument that it couldn't have avoided additional capital expenditures by putting Unit 2 in preservation mode sooner. Agrees with the PD that SCE knew or should have known by March 15 2012 that the potential design defect was present in both units.

SDG&E is part owner of SONGS, and thus the PD's allocation of the 20% share of the disallowance in its SONGS is reasonable; the PD does not impute SCE's actions as owner to SDG&E.

Additional A&G costs should be included in the disallowance. Doesn't quantify the amount, but says the O&M (10% per month) "ramp down" mechanism in the PD should also be applied to A&G costs.

Disagrees with SCE's comment that it should be able to argue in Phase 3 that some portions of the power replacement costs should not be subject to disallowance; SCE should not be able to reserve this argument for the future.

Coalition to Decommission San Onofre

Supports PD but thinks the amount of the refund is overly conservative based upon the record cited in the PD. Advocates an 80% Base O&M disallowance for June-December 2012; and disallow 20% of the refueling for Unit 2 (PD approves the whole thing), and disallow 56% of Cap X (PD cuts by 20%).

Some comments re emergency planning , coordination with state and local governments and public education.

WEM

One issue: WEM believes that SCE misused community outreach funds to promote SONGS/convince community that it was clean safe and affordable. The PD acknowledges that some of SCE's materials have a self-serving component.

World Business Academy

PD should use clear and convincing evidence standard of review because this is not a standard GRC, it is a "specialized proceeding."

PD FOF 10 states that on March 15, SCE knew or should have known that the TTW problem was a potential design defect in both units 2 and 3. PD p. 3, FOF 18 and COL 2 and 3 state that by May 7th, SCE knew or should have known that TTW problem in Unit 3 was also present in Unit 2. So, they question why May 7th was used as the date for the O&M disallowance, and not March 15. They say that March 15 should be the relevant non-recovery date.

The 20% reduction for capital expenses applied in the PD is not supported by substantial evidence, and is based on SCE's testimony which is not reliable.

Chinese American Institute for Empowerment, Black Church Group, Latino Business Council, et al. (Coalition representing minority groups)

They believe that "this proceeding should not be used to permanently end nuclear power as a potentially effective and safe alternative to fossil fuels." Have to consider the financial implications and California's clean energy goals before banning any one resource, and this reflects the views of the minority population.

Coalition of California Utility Employees (CCCUE)

One issue: disagrees with PD's conclusion that SCE was unreasonable in maintaining full staff after May 2012. CUE argues these are highly trained workers that would have been needed if they restarted the facility.

SONGS OII I.12-10-013 **January 16th Agenda Item __**

Proposed Decision on Phase 1 Regarding 2012 SONGS-Related Expenses and Expenditures (Florio/Darling/Dudney)

(Summary prepared by Charlyn Hook)

This Phase 1 decision is focused on the reasonableness of the 2012 expenditures and how SCE responded to the tube wear problems discovered in January 2012 on the steam generators in Units 2 and 3.

I. Basic Info:

SONGS All Party: Jan 15th 1:30 pm.

SONGS is jointly owned by SCE (78%), SDG&E (20%) and the City of Riverside (2%). The numbers in the PD are talking about the total share for the two CPUC-jurisdictional utilities.

Both Units 2 and 3 have been non-operational since Jan. 2012.

When operational, SONGS provided approx. 2200 MW of base load power, and voltage support to the LA area.

The NRC has safety and regulatory jurisdiction over SONGS; we have jurisdiction over rates.

Acronyms:

2 similar acronyms used in the PD – not the same thing:

Steam Generator Replacement Project (SGRP)

Steam Generator Inspection and Repair or (SGIR). (see explained below in the phases overview.)

II. Overview of Phases of SONGS OII:

There are 3 phases to the SONGS OII

Phase 1: scope includes determining the reasonableness of SONGS-related expenditures in 2012; these costs include removal of fuel from Unit 3, operating and maintenance costs (this broken down in PD into Base O&M and Steam Generator Inspection and Repair or **"SGIR"** O&M), community outreach and emergency preparedness, and if any of the rates preliminarily approved in the 2012 GRC should be refunded. The SONGS outage occurred during the pendency of the SDG&E and SCE

GRC's; 2012 costs were approved in the GRCs, subject to refund, and a memo account (the SONGSMA) was established in both cases.

<u>Phase 1A</u>: is to determine a methodology for approximating replacement power costs necessitated by the SONGS outage. (this was going to be a separate PD, but they rolled it into Phase 1.)

<u>Phase 2</u>: this phase designed to deal with whether and when the SONGS plant and O&M should be removed from ratebase going forward since the plant is no longer in service; evidentiary hearings were held on this last year, and a PD is coming.

<u>Phase 3</u>: this phase will look at the causes of the steam generator damage and allocation of responsibility. (Mitsubishi Heavy Industries (MHI) is the manufacturer and/or designer of the tubes that caused damage.) While Phase 1 is limited to 2012 costs (including the SGIR O&M costs), Phase 3 will looks at the utilities two applications for recovery of costs related to the Steam Generator Replacement Project (**SGRP**). The Commission approved the SGRP in a 2005 decision (D.05-12-040); the Commission authorized up to $680 million (2004 dollars) for removal and replacement of the steam generators in units 2 and 3; the utilities filed applications in 2013 to recover the actual amounts spent on the SGRP. SCE's application indicated it spent $768.5 million (nominal dollars).

<u>III. Summary of the Phase 1 PD:</u>

This Phase 1 PD does two things: (1) adopts an interim rate reduction for SCE and SDG&E ratepayers for 2012 operating costs; and (2) determines a methodology to be applied going forward for assessing the replacement power costs.

The PD looks mainly at how SCE responded to the discovery of the problems with the tubes in the steam generators in 2012. The crux of the PD is an assessment of what point in the Spring of 2012 that SCE knew enough about the causes and conditions of the Tube to Wear (TTW) problems in its steam generators on Units 2 and 3, to know that it would not be economically viable to continue operating these units and incurring O&M costs. The PD's reasoning is factually based on the timeline of events; there is a full timeline in Appendix C to the PD, so I will highlight only a few key dates below.

<u>A. Ratepayer Refund for 2012 (Phase 1)</u>

The PD establishes refunds due to customers for 2012 costs deemed unreasonable in the PD.

Summary of Refund (summary table in PD p. 97)

Summary of Adopted Ratemaking
100% share, 000s of 2012$

Cost Category	Adopted	Refund in 2014 Rates	Review in Phase 3
Base O&M	$273,867	$73,880	
SGIR O&M	$18,353		$122,603
Other O&M (Corp. Support, IT, Severance)	$1,663	$4,527	
Subtotal	$293,883	$78,407	$122,603
RFO O&M	$45,077		
Seismic	$4,077		
Capital Expenditures	$134,080		
Capital Additions	($33,520)	($500)	
Replacement Power			To be calculated
2012 Revenue Requirement due to O&M and Capital Adjustments		($93,522) SCE: ($74,222) SDG&E: ($19,300	

The disallowance for Base O&M of $73,880 represents about a 21% disallowance. For Capital Expenditures, the $134,080 disallowance is also about 20%. However, the PD explains that it does not result in a rate reduction due to the resulting inability to claim bonus depreciation under the Tax Relief Act of 2010.

*SGIR O&M – Considered in Phase 3; no refund at this time, total amount at stake is $122,603, and costs must continue to be tracked in a memo account. Phase 3 will also consider the possibility that SCE will recover some proceeds Mitsubishi (MHI) the tube manufacturer, or from insurance.

Timeline/Reasoning of PD:

Jan. 10 2012	SONGS Unit 2 scheduled for an outage for refueling. (referred to as the RFO). The initial plan was to have Unit 2 back online by March 5th.
Jan. 31 2012	Unit 3 taken off line due to a tube leak problem.
Spring 2012	SCE investigated the causes of the Tube to Wear (TTW) problems in the steam generators, MCI undertakes a root cause analysis. NRC informs SCE that it cannot re-start units 2 and 3 without NRC approval.
Pre-March 15 2012	PD reasons that up to March 15, SCE acted as a reasonable operator. Therefore, SCE can recover Steam Generator

	Inspection and Repair (SGIR) costs necessary for ordinary operations up to this point in time.
Post-March 15 2012	PD reasons that SCE knew of design defects and the TTW problems on both Unit 2 and 3; the problems were discovered on Unit 3, but Unit 2 is similar (possibly identical) in design. Therefore, SCE's Steam Generator Base Inspection and Repair (SGIR) O&M costs may be subject to further review/refund in Phase 3. The Commission approved the SGRP program in 2005, so reasonable rate recovery is authorized. The risks of the SGRP program as a whole will be looked at in Phase 3.
April 2012	SCE provided the Commission with a root cause analysis report on the TTW problem. Therefore, SCE definitely knew it had serious problems by April 2012.
April 26, 2012	PD states that SCE unrealistically advised its Board that Units 2 and 3 would return to service by June of 2012, despite the fact that they needed NRC approval.
May 7, 2012	PD reasons SCE's decisions to continue spending on the restart of Units 2 and 3 were not reasonable, because they did not consider the costs, and regulatory obstacles of restarting the units. PD states that by this date, SCE knew or should have known that Unit 2 may not restart, but was "singularly focused on the restart option." (p. 36.)
June 2012	SCE was planning to put Unit 3 in preservation mode, therefore it should have known that Unit 2 was similarly situated. By June 7 – SCE announces that it would not restart Units 2 and 3 and would seek decommissioning approval. Therefore, the PD implements a gradual disallowance of O&M costs. (10% per month) for June through December 2012.

B. Replacement Power Costs Methodology (Phase 1A).

A methodology for calculating the approximate cost of replacement energy and capacity costs necessitated by the outage of SONGS. All parties agree that these costs can only be approximated, because we can't ever know what the market price would have been if the outage did not happen.

The PD adopts a methodology for calculating the power costs, but these costs won't be determined until Phase 3.

The PD defines replacement costs as the net increase in cost to the utility to meet its energy and capacity needs for bundled customers. This definition includes consideration of cost of replacement generation, revenues from sales, capacity, DR costs, onsite load, some Congestion Revenue Right related costs, but not EE costs. (Much more detail in the PD.)

Basic formula: Quantity (net short/long position) x Price ($ MWh) = Hourly Replacement Energy Cost (or Forgone Sales).

Apart from agreeing that any formula is an approximation, the parties differed greatly in what the methodology should be, and there is a thorough discussion in the PD of the parties's proposals.

IV. Other Parties' Positions

The PD indicates that **TURN and ORA** are taking a more extreme position on the disallowance. They argue that SCE should recover no capital costs after January 31, 2012, when both units were offline. They argue there should be no SGIR costs, no O&M costs for 2012 have been proven reasonable. DRA would only agree that some safety-related costs should be allowed.

The PD finds that ORA's approach is "too blunt" because SCE did not know by Jan. 31 that both units would never return to service.

<u>SCE – Dec. 9th meeting handout</u>. 3 main points:

1. The PD wrongly criticizes SCE for working to restart Unit 2. SCE says it was working on the 70% restart plan for Unit 2, that it expected the NRC to approve this in about 60 days (this may have been optimistic), and also that it wasn't clear from the scoping memo that they were going to have to litigate this issue, and the record is unclear on this point in their view. They request that the PD be withdrawn and the record re-opened to further evaluate the issue of SCE's reasonableness in pursuing the re-start of Unit 2 issue.

2. The PD wrongly criticizes SCE for failing to put Unit 2 in preservation mode and reduce staffing after May 2012. They say it wasn't feasible to lay people off not knowing the future status of the unit's return to service.

3. With respect to the replacement power cost methodology, the PD should not prejudge policy questions of which categories of market-related costs should be disallowed if imprudence is found in Phase 3. The PD should be clarified that to indicate that parties may advocate that some market costs should NOT be disallowed.

Tab 4

PUBLIC UTILITIES COMMISSION
STATE OF CALIFORNIA
505 VAN NESS AVENUE
SAN FRANCISCO, CALIFORNIA 94102

MICHAEL R. PEEVEY
PRESIDENT

TEL: (415) 703-3703
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March 13, 2012

Jackalyne Pfannenstiel
Assistant Secretary of the Navy
1000 Navy Pentagon
Washington DC 20350-1000

Dear Assistant Secretary Pfannenstiel:

Thank you for your letter concerning the Navy's Smart Power Partnership Initiative (SPPI) in California and some of the barriers that the Navy is encountering in its implementation. The goals the Navy has set are admirable and the California Public Utilities Commission (CPUC) supports the Navy's smart grid and renewables initiatives in California. I commit to working with you to resolve the regulatory and statutory limitations to achieve the goals that are mutually beneficial to the Department of the Navy and the State of California.

Our first review of some the barriers mentioned in your letter shows their complexity. Resolving the problems will not only take the efforts of this CPUC, but other state and federal agencies, the regulated electric utilities, the California Independent System Operator, and maybe the legislature. Almost all of the issues identified require changes in statute or regulations set by other state or federal agencies. Even with these complexities we should be able to work together and solve some of the problems. I have instructed CPUC staff to reach out to the Navy and find real solutions that will help you meet the aggressive goals you have set.

The CPUC recently hosted one all-day meeting with all of the branches of the military to discuss a vast range of clean energy programs in California. That meeting was focused largely on CPUC staff providing overview of the available clean energy programs, and resulted in an agreement for more specific follow up meetings. We can use these meetings as a starting point for our new efforts. CPUC staff should be contacting Navy personnel shortly to provide more assistance. In the meantime please feel free to have them contact Carol Brown in my office or Edward Randolph, the Director of CPUC's Energy Division.

Michael R. Peevey
President

cc: Michael Picker, Office of the Governor of California
Robert Weisenmiller, Chair, California Energy Commission
Wade Crowfoot, Deputy Director, Governor's Office of Planning and Research
Karen Edson, Vice President, Policy and Client Services, California ISO

431574

Tab 5

DEPARTMENT OF THE NAVY

THE ASSISTANT SECRETARY OF THE NAVY
(ENERGY, INSTALLATIONS & ENVIRONMENT)
1000 NAVY PENTAGON
WASHINGTON DC 20350-1000

President Michael R. Peevey
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

FEB 13 2012

Dear President ~~Peevey~~ Mike:

I am writing to follow up on our meeting last October regarding the Department of the Navy's (DoN's) regional smart grid initiative, the Smart Power Partnership Initiative (SPPI.) I would also like to bring to your attention a significant related issue – the barriers we are encountering as we attempt to achieve our, and the State's, renewable energy goals. It has become increasingly clear that some regulatory and/or legislative modifications will be needed for us to be able to accomplish the ambitious renewable energy goals shared by the DoN and the State of California.

On the SPPI, we continue to receive encouraging support from all involved stakeholders, including the Governor's Office, the Energy Commission, the ISO, and San Diego Gas and Electric (SDG&E), among others. We have a core team in place at our Naval Facilities Engineering Command Southwest in San Diego that is developing a pilot with the support of technical consultants and expertise from many of the stakeholders noted above. Working with SDG&E, we are preparing to conduct a series of demand response table top exercises and actual controlled load reduction events over the next few months. These tests will help us better understand the load aggregation and deferment opportunities we have across our DoN bases in the Southwest. I remain convinced that, working with our partners, we will demonstrate an effective regional smart grid that can be exported to other states and regions.

As we have said, one important attribute of a regional smart grid will be its ability to "share" renewable resources across the regional bases. That is especially evident in southern California where we have a few installations where the potential for renewable power generation significantly exceeds those installations' needs. It has been our intention to support the development of renewables beyond the requirements of a single base and be able to send the excess into the grid for use on other bases or elsewhere in the State.

Our commitment to the development of renewables on our bases was highlighted by President Obama's announcement in his State of the Union address that the Navy will purchase enough renewable energy to power a quarter of a million homes – or, as the

Secretary of the Navy has stated, DON will produce or purchase one gigawatt of renewable energy. We made this commitment because we recognize that energy security is fundamental to national security.

A large portion of the gigawatt of renewable energy is likely to come from our California bases in the form of new solar, wind, and geothermal development. However, the lack of transmission capacity, coupled with a number of regulatory and legislative requirements, have stymied our efforts to optimize the renewable potential of the California bases. The most serious issues we are confronting are described below.

- The single most critical impediment to our renewables development in California is the lack of transmission capacity in the vicinity of those installations with the best potential for renewable energy production. As an example, transmission constraints at our China Lake Weapons Station, adjacent to Ridgecrest, have limited development on that base to the 13.78 MW PV project currently under construction. This is unfortunate since there is a great deal more renewable energy potential at this location. We have been told by SCE that relief from this constraint will take 8 years.

- The current capacity limit for net electric metering (NEM) is 1MW. DoN installations are typically considered to be a single "site" or "premise" per application of the utilities' Rule 1 definitions; this severely limits the ability of installations to develop more than 1MW of renewables, regardless of the installation's load or capacity to support renewable projects. For example, a recently installed 1.5MW wind turbine at MCLB Barstow has been "turned down" to 1MW in order to qualify for the NEM program.

- In southern California, all existing generation must be retrofit with telemetry once the 1 MW threshold is crossed, which is a significant expense and deterrent. The telemetry is required even if the generation assets are well below the load of the installation and there is little prospect of export to the grid. For example, one installation is being required to install telemetry infrastructure (at a cost of over $800,000) on approximately 1MW of generation even though the minimum baseload is 8MW and there is almost no possibility of generation ever exceeding the installation's load.

- Standby and departing load charges discourage the development of RE by imposing significant costs that offset the savings from the renewable energy production. For example, the recently-awarded 14 MW project at NAWS China Lake, will cause the base to incur approximately $650,000 in departing load and $1M in standby charges annually. These charges will potentially be offset by a $2M reduction in demand charges, but the reductions will not be realized if the system does not produce at full capacity during times of peak demand.

We would like to work closely with you and the other stakeholders to consider how to address this set of issues. Specifically, and most urgently, we would like to see, and would commit to engaging in, a process that would resolve the transmission constraints at our installations. I would encourage you to personally lead a team that would consist of the Chair of the Energy Commission, representative(s) from the Governor's office, a senior representative from the ISO, and the DoN to focus specifically on the potential development of renewable resources at DoN installations in California. I have tasked my team in the Southwest to remain engaged with your office and others to help identify coordinated solutions.

The Department of the Navy has made a strong and significant commitment to the development of renewable energy. Our California installations are critical to meeting our renewables goals, as they are to meeting California's RPS. I ask that you make eliminating the barriers to renewables development for the Department of the Navy a high priority of the Public Utilities Commission. I look forward to working with you on this matter of national and state concern.

Jackie

Jackalyne Pfannenstiel

Copy to:
Mr. Michael Picker. Office of the Governor of California
Robert Weisenmiller, Chair, California Energy Commission
Mr. Wade Crowfoot, Deputy Director, Governor's Office of Planning and Research
Karen Edson, Vice President, Policy and Client Services, California ISO

Tab 6

Message

From:	Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Sent:	2/18/2014 3:53:02 PM
To:	Picker, Michael [Michael.Picker@cpuc.ca.gov]
Subject:	LTPP decision and San Onofre Documents
Attachments:	40 [12720] Gamson Proposed Decision (.pdf; Briefing on NUCLEAR ISSUES by ED staff.doc; PD re Phase 1 2012 SONGS Expenses.pdf; SONGS briefing doc from ALJs Darling & Dudney.doc; SONGS PD Summary of Party Comments chh.docx; SONGS Phase 1 PD Summary chh.docx

Michael
Attached is the LTPP decision we discussed earlier today. We are still trying to ascertain whether the San Onofre proposed decision will be on the agenda for next week, but in case it is, I am attaching all the relevent documents.
Nick

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
1-28-14
11:33 AM

January 28, 2014

Agenda ID #12720
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 12-03-014:

This is the proposed decision of Administrative Law Judge David M. Gamson. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's February 27, 2014 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:sbf

Attachment

ALJ/DMG/sbf **PROPOSED DECISION** Agenda ID #12720
Ratesetting

Decision **PROPOSED DECISION OF ALJ GAMSON** (Mailed 1/28/14)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

DECISION MODIFYING LONG-TERM PROCUREMENT PLANNING RULES

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DECISION MODIFYING LONG-TERM PROCUREMENT PLANNING RULES

1. Summary

This is the Track 3 decision in the 2012 long-term procurement plans proceeding, regarding long-term procurement rules. This decision makes several rule changes for utility procurement of electricity in California:

1) Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the IOUs) shall estimate reasonable levels of expected Direct Access (DA) and Community Choice Aggregation (CCA) departing load over the 10-year term of the IOUs bundled plans, using information provided by the California Energy Commission and/or by a CCA in its Binding Notice of Intent. The IOUs shall then exclude this departing load from their future bundled procurement plans, and only procure for the assumed amounts of retained bundled load. Having been excluded from the bundled portfolio planning scenarios, the forecasted Direct Access and Community Choice Aggregation departing load shall not be subject to non-bypassable charges for any incremental stranded procurement costs incurred by the IOUs for the period after the date of departure assumed in their approved bundled plans.
2) In order to allow incremental capacity to bid into a new generation Request for Offers, the term "incremental capacity" is defined as: "capacity incremental to what was assumed in the underlying needs assessment." In addition, the terms "upgraded plants" and "repowered plants" are also defined.
3) The IOUs shall submit Tier II Advice Letters seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 megawatts. This rule is in addition to all previous procurement rules.

4) Energy auctions shall no longer be required to net capacity costs for facilities subject to the Cost Allocation Mechanism. Instead, the IOUs shall use the mechanism adopted in Decision 07-09-044, known as the "Joint Parties' Proposal," to set the residual capacity costs that would be allocated to benefitting customers.

5) Independent evaluators shall remain in the selection pool without term limits, subject to evaluation every three years instead of every two years.

2. Background

This proceeding is the successor proceeding to rulemakings dating back to 2001 intended to ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers. The most recent predecessor to this proceeding was Rulemaking (R.) 10-05-006. As stated in the order originating this rulemaking in Ordering Paragraph 3, the record developed in R.10-05-006 is "fully available for consideration in this proceeding" and is therefore incorporated into the record of this proceeding.

In the Scoping Memo for this proceeding, issued on May 17, 2012, the general issues for the 2012 procurement planning cycle were divided into three topics:

1. Identify Commission-jurisdictional needs for new resources to meet local or system resource adequacy (RA), renewable integration, or other requirements and to consider authorization of IOU procurement to meet that need. This includes issues related to long-term renewable planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through cooling technology (OTC);
2. Update, and review individual IOU bundled procurement plans consistent with Public Utilities Code Section 454.5; and

3. Develop or refine procurement rules that were not resolved in R.10-06-005, and consider other emerging procurement policy topics.

The Scoping Memo, along with a Revised Scoping Memo issued May 21, 2013, divided the proceeding into four Tracks:

1. Track 1 was the "Local Reliability" track. This track concluded with Decision (D.) 13-02-015.
2. Track 2 was the "System Reliability" track. D.12-12-010 was issued in this track adopting scenarios for analyzing system reliability. A Ruling issued September 16, 2013 cancelled Track 2 and deferred such issues to the next long-term procurement plans proceeding (LTPP) Rulemaking.
3. Track 3 is the "Procurement Rules and Bundled Procurement Plans" track. This is the decision regarding procurement rules as part of Track 3 in this proceeding. The Revised Scoping Memo did not set a schedule for filing of bundled procurement plans.
4. Track 4 is the "San Onofre Nuclear Generating Station (SONGS)" track. Track 4 will consider the local reliability impacts of a long-term outage at SONGS generators, which are no longer operational. The Revised Scoping Memo set a schedule for this track.

The Commission maintains a Procurement Policy Manual[1] which provides all of the requirements and guidance provided by the Commission to its jurisdictional entities under Public Utilities Code Sections[2] 380, 454.5, and 399.11-399.20.[3] AB 57 was codified as Section 454.5, which sets forth the

---

[1] This document (also known as the Rulebook) can be found on the Commission's website.

[2] All Code Section references are to the Public Utilities Code, unless otherwise noted.

[3] The Procurement Policy Manual was most recently updated on June 2, 2010.

statutory framework for Commission review of utility procurement plans. Section 454.5 requires that the IOUs prepare procurement plans for review and approval by the Commission and ensures that all costs associated with transactions executed by an IOU in accordance with its Commission-approved procurement plan will be fully recoverable. Procurement plans are generally prepared every other year following the adoption of official load forecasts by the California Energy Commission (CEC) in its biennial Integrated Energy Planning Report process.

Section 454.5(b) sets forth the elements which an electrical corporation's proposed procurement plan for its bundled customers must include. Section 454.5(d) sets forth the requirements for the commission to review and accept, modify, or reject each electrical corporation's bundled procurement plan.

Since the Procurement Policy Manual was last updated in 2010, D.12-04-046 (in R.10-05-006,the 2010 long-term procurement plans (LTPP) proceeding) further addressed rules issues, including: procurement rules relating to power plants using once-through cooling; a proposal from Southern California Edison for a new generation auction; refinements to evaluating bids where utility-owned generation and independent generation are competing; utility procurement of greenhouse gas related products; a request from the Independent Energy Producers relating to generator recovery of greenhouse gas compliance costs; and general procurement oversight rules.

The Scoping Memo in this proceeding at 11 set forth the following expectation for Track 3 of this proceeding:

> There will be two portions of Track 3. First we will consider what changes should be made to current procurement rules, as well as what new procurement rules should be adopted.

Second, and after a decision on procurement rules, we will require the IOUs to file bundled procurement plans.[4]

This decision involves the first portion of Track 3, regarding procurement rules. A March 21, 2013 Ruling set forth a series of questions regarding Track 3 rules issues for parties to comment upon. The questions are delineated in sections of this decision. Parties filed comments on Track 3 rules issues on April 12, 2013. Parties filed replies to comments on April 26, 2013.

The parties which filed comments in Track 3 of this proceeding are: AES Southland (AES); Alliance for Retail Energy Markets and, Direct Access Customer Coalition (AReM/DACC); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA); Calpine Corporation (Calpine); City and County of San Francisco (CCSF); Clean Coalition; Competitive Power Ventures, Power Development Inc. (CPV); Division of Ratepayer Advocates (now Office of Ratepayer Advocates or ORA); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Marin Energy Authority (MEA); NRG Energy (NRG); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (US), L.P. (Shell); Sierra Club California (Sierra Club); Southern California Edison Company (SCE); South San Joaquin Irrigation District (SSJID); TAS Energy (TAS); The Utility Reform Network (TURN); and Western Power Trading Forum (WPTF); Women's Energy Matters (WEM).

3. PG&E September 20, 2012 Motion

On September 20, 2012, PG&E filed a Motion to move the Track 3 multi-year procurement issue to the RA proceeding. PG&E argues that there

[4] Bundled procurement plans will be next considered in the 2014 LTPP proceeding.

appears to be an emerging consensus among the parties that participate in the various procurement-related proceedings at the Commission that the current, one year forward RA program should be improved in at least two respects. First, PG&E maintains that the RA program should take into account the need for some level of resource "flexibility" in order for the system to be operated reliably. Second, PG&E argues that the current, one-year forward RA procurement requirement applicable to all load serving entities should be extended to a multi-year timeframe, as the ISO has expressed that the current one-year forward requirement does not provide it with adequate assurances that the resources needed to operate the system will be available.

PG&E notes that flexibility is being addressed in the RA proceeding and the multi-year procurement requirement is currently slated to be addressed in Track 3 of this proceeding. PG&E requests that the two issues be considered together in the RA proceeding where efforts are already underway to address flexibility. PG&E asserts that these two topics are too closely related to be separated artificially, and the consolidated approach will increase administrative efficiency, both for the Commission and for the interested parties. PG&E also requests that all Track 3 issues be deferred to after the completion of Track 2. On October 5, 2012, several parties responded to PG&E's Motion, both in favor and opposed to all or part.

We will deny PG&E's Motion. We deny as moot PG&E's request to defer all Track 3 issues until after Track 2 is complete, because Track 2 was cancelled per a September 16, 2013 Ruling. Instead, we will address the limited subset of Track 3 issues which were encompassed by the March 21, 2013 Ruling. We will not consider flexibility issues or multi-year contracting issues in this decision. A recent RA decision (D.13-06-024) adopted an interim definition of flexibility.

Further issues regarding flexibility for RA purposes will continue to be addressed in the RA proceeding, R.11-10-023 or its successor. We also will not address multi-year contracting issues in this decision; the Commission at its November 14, 2013 meeting indicated these issues would be considered in a separate Rulemaking.

4. Maximum and minimum limits on IOU forward purchasing of energy, capacity, fuel, and hedges

4.1. Question:

Should the Commission modify the AB 57 bundled procurement guidelines to indicate minimum and maximum limits for which the three IOUs must procure for future years? If so, should these minimum and maximum limits address energy, system RA, local RA, and/or flexibility?

4.1.1. Current Rule

Ordering Paragraph 1 of D.12-01-033 approved the IOUs 2010 bundled procurement plans. Ordering Paragraph 2 of that decision stated: "Approval of PG&E's and SDG&E's bundled procurement plans includes the incorporation of position limits and maximum rates of transactions, as proposed by the companies in their comments on the Proposed Decision." The approach adopted by the decision is spelled out at. 14-15:

> PG&E and SDG&E, however, propose (in almost identical language) an alternative approach, under which they would use an approach based on that of SCE:
>
> > PG&E [SDG&E] is willing to modify its BPP in order to establish position limits similar to those of SCE. Specifically, the portion of SCE's methodology that PG&E [SDG&E] is willing to adopt is contained in Section 3 (Procurement Limits and Ratable Rates) of SCE's proposed 2012 bundled plan. PG&E [SDG&E] proposes to follow the methodology set forth in subsection (b) of Section 3, which

> applies to bundled system capacity procurement, and subsection (f), which applies to transaction compliance accounting and limit updates. PG&E [SDG&E] would adopt these aspects of SCE's bundled plan and apply them to PG&E's [SDG&E's] bundled procurement in the same manner as detailed in SCE's bundled plan. [Citations deleted]
>
> This proposed approach provides additional protection to ratepayers, and allows us to find that the utilities' proposed bundled procurement plans, as modified by this decision, are reasonable under § 454.5. Accordingly, we adopt the alternative approach proposed by PG&E and SDG&E, modeled on SCE's bundled procurement plan, rather than the cost cap approach set forth in the Proposed Decision.

4.1.2. Parties' Positions

PG&E supports procurement limits on electricity and natural gas purchases for its electric portfolio, RA, and greenhouse gas (GHG) compliance instruments, including position and execution limits, but recommends that minimum limits for positions and executions be set only to the extent the Commission desires a minimum level of hedging to manage bundled customer risk. PG&E claims it is premature to consider minimum and maximum limits for flexible capacity, or to meet the one-year-ahead system RA requirement.

SCE recommends that the Commission not modify the guidelines. SDG&E states that minimum and maximum procurement limits for energy products are already addressed in SDG&E's bundled plan.

IEP recommends the Commission adopt guidelines to provide the IOUs with the authority to procure resources needed to meet procurement targets and ensure grid reliability. Calpine and NRG believe that all load serving entities should be subject to mandatory multi-year forward procurement requirements. WPTF contends the issue of forward market procurement requirements needs to be addressed both here and in the RA docket, R.11-10-023. WPTF supports both the implementation of a multi-year forward capacity obligation for all load serving entities (LSEs) and the implementation of a centralized capacity market.

AReM/DACC argues that the Commission should establish minimum limits for IOU procurement to comply with the requirements of AB 57 to procure energy, capacity and reserves sufficient to serve their bundled loads over the long term.

ORA believes the Commission should not establish a minimum limit for forward procurement in the absence of an adequate record and stakeholder process for developing the limit and allocating costs. TURN is concerned that imposing minimum and maximum limits for procuring any particular electric product or service could increase IOU costs for serving bundled customers.

Sierra Club contends the Commission should establish maximum limits for the purchase of fossil fuel resources, which should be established to implement the loading order and minimize the use of fossil fuels. CEJA offers that the Commission should include limits on forward purchasing of energy and capacity because forward purchasing of GHG compliance instruments is not a reliable way to meet the goals of AB 32 and does not safeguard ratepayers. WEM suggests that the rules for bundled procurement should limit new fossil-fueled resources to zero, except for combine heat and power (CHP) and potentially the repowering of OTC plants.

4.1.3. Discussion

We will not establish new minimum or maximum procurement levels for bundled procurement plans at this time.

The three IOUs all correctly point out that minimum and maximum procurement limits are already addressed in their bundled procurement plans.

The current bundled procurement plan framework, under the Procurement Policy Manual rules established pursuant to AB 57 (as most recently updated by D.12-04-046), provides adequate assurance that the IOUs will not procure any products in excess of the forecasted need, and will not procure any products to reduce portfolio risk if such procurement is inconsistent with the Commission-approved Customer Risk Tolerance level. IOU procurement of authorized energy, natural gas, emissions and financial hedging products is restricted by predetermined volume limits and transaction rate limits approved in the bundled procurement plan, based on a forecast of future procurement needs. In effect, the bundled procurement plan already provides an upper limit on procurement.

Parties such as Sierra Club call for maximum procurement levels for fossil-fuel resources or minimum procurement levels for preferred resources. We are committed to goals related to GHG reduction and to the Loading Order prioritization of preferred resources (energy efficiency, demand response and renewable resources) over fossil-fuel resources. There are a number of proceedings which seek to implement statutes, policies and goals in these important areas. In the 2006 LTPP proceeding, D.07-12-052 at 3-4 stated:

> Going forward the utilities will be required to reflect in the design of their request for offers (RFO) compliance with the preferred loading order and with GHG reduction goals and demonstrate how each application for fossil generation comports with these goals… (W)e will require that subsequent LTPP filings for our regulated utilities not only conform to the energy and environmental policies in place, but aim for even higher levels of performance. We expect the utilities to show a commitment to not only meet the targets set by the Legislature and this Commission but to try on their own to integrate research and technology to strive to improve the

> environment, without compromising reliability or our obligation to ratepayers.

We reiterate this exhortation to the utilities and continue to expect every reasonable effort to meet or exceed environmental goals, consistent with reliability and cost. Section 454.5(b)(9) requires "a showing that the procurement plan will fulfill its unmet resource needs from eligible renewable energy resources in an amount sufficient to meet its procurement requirements pursuant to the California Renewables Portfolio Standard Program" and "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." This obligation is ongoing.

In a 2010 LTPP decision (D.12-01-033 at 20) on bundled procurement plans, we states that "the utility obligation to follow the loading order is ongoing…even if pre-set targets for certain preferred resources have been achieved." However, in that decision at 21-22, we stated that this obligation was limited to preferred resources that are "feasibly achieved and cost effective." Similarly, in the Track 1 decision (D.13-02-015) in this proceeding, we strove to meet the objectives of Section 454.5(b)(9) while also maintaining reliability and reasonable rates. In that decision, we authorized procurement of significant levels of preferred resources (and energy storage resources), along with minimum and maximum level of fossil-fuel resources to meet local reliability needs.

We will not establish additional rules for a maximum level for fossil-fuel resources. We take ORA's point that, while there are potential benefits of mandating minimum procurement limits, the record in this proceeding is inadequate to ensure that bundled customers would not bear a disproportionate share of reliability costs. Instead we will continue to implement and balance

Commission environmental, reliability and rate requirements consistent with specific needs in each bundled procurement plan, while ensuring Section 454.5(b)(9) is followed. We will also not establish minimum procurement levels for preferred (or any other) resources in this proceeding, but will review the upcoming bundled procurement plans to ensure they continue to incorporate other relevant Commission environmental directives from other proceedings.

Minimum procurement levels are already established in the RA proceeding, as shown in Rule RA.2. All Commission-jurisdictional LSEs are required to demonstrate procurement of 90% of their next year's system RA requirement and 100% of their next year's local RA requirement on a year-ahead basis, as well as 100% of their system RA requirement on a month-ahead basis. Further, per Rule G.1(c), LSEs are not to rely, on a planning basis, on the spot market for more than 5% of their energy purchase requirement (with specified exceptions). In addition, we agree with SCE that if the market is aware that the IOU has an additional minimum procurement obligation, counterparties may have an incentive to raise their prices as the IOU is required to purchase to certain levels. We agree with TURN that additional minimum procurement requirements for any particular electric product or service could increase ratepayer costs. At this time, we see no corresponding or overriding benefit to further minimum procurement requirements.

Issues regarding centralized capacity markets are not within the scope of this proceeding. Similarly, we will not consider multi-year forward contracting here. Issues regarding limits on flexible capacity are encompassed in the RA proceeding.

4.2. Question:

How may the Commission best balance issues regarding departing load in any future requirements for procurement?

4.2.1. Current Rule

Regarding procurement planning, Ordering Paragraph 8 of D.12-01-033 states: "Southern California Edison Company is authorized to use its proposed direct access assumptions, and the other utilities should procure consistently with those assumptions." That decision at 30 explains further:

> SCE includes in its forecast the maximum allowable phase-in of new direct access sales permitted under Senate Bill (SB) 695, which are greater than under the Standardized Planning Assumptions. Specifically, SCE forecasts that the Commission-authorized increase in direct access would be fully subscribed in each year until 2013, consistent with D.10-03-022. SCE argues that their assumptions are more consistent with SB 695 and D.10-03-022 than the standardized planning assumptions.
>
> We agree with MEA and SCE on this issue. It is appropriate to use more accurate load forecasts for MEA, consistent with SB 695, instead of the load forecast in the standardized planning assumptions. SCE is authorized to use its direct access assumptions for purposes of establishing position limits and ratable rates for its bundled procurement plan. The other utilities should engage in procurement consistent with SCE's assumptions for direct access. (*footnotes and references omitted*)

4.2.2 Parties' Positions

PG&E notes that each IOU's bundled procurement plan incorporates departing load forecasts and there is no need for additional Commission action on this issue. SCE agrees that its forecast of the future need to procure energy products reasonably accounts for departing load. SDG&E suggests that departing load issues associated with multi-year forward procurement requirements should be addressed in the ongoing RA proceeding.

IEP recommends establishing clear rules and procedures to explain how costs associated with IOU procurement follow departing load. WPTF believes the Commission should clarify that the IOUs are to plan for reasonable amounts of departing load and then only procure for the assumed amounts of retained bundled load.

AReM/DACC recommends that the IOUs should be required to estimate reasonable levels of expected DA (Direct Access)/Community Choice Aggregators (CCA) departing load over the 10-year term of the bundled plans and should then exclude this load from their future resource plans and procurement activities. Having been excluded from the planning scenarios, the forecasted departing DA and CCA load would not be subject to any non-bypassable charges, either stranded costs or cost allocation methodology (CAM), for procurement costs incurred by the IOUs after approval of the bundled plans.

SSJID states that the Commission requires IOUs to use reasonable assessments of future conditions, rather than the most conservative assessments, when faced with load and supply uncertainty in their procurement forecasts. Thus, SSJID concludes that PG&E should not procure capacity on behalf of SSJID because SSJID is in the process of undertaking to provide retail electric service within its existing service area. Specifically, SSJID contends it would be unreasonable and imprudent for PG&E not to account for SSJID's planned municipalization in its departing load forecasts.

MEA believes the Commission should direct the IOUs to incorporate reasonable estimates for CCA departing load in their bundled procurement plans. The IOU procurement plan should be evaluated, in part, on its resilience to varying levels of departing load without creation of stranded costs. Sierra Club recommends that the bundled plans should plan and account for a certain amount of departing load. WEM argues that the Commission should develop policies that move the utilities out of the way of others providing what customers want, or push the utilities more effectively towards revising their business models in these directions.

4.2.3. Discussion

We agree with the concept expressed by most parties that the IOUs should plan for reasonable amounts of departing load in their bundled plans and then only procure for the assumed amounts of retained bundled load. We also agree that the IOUs do, at this time, appear to take into account their expectations for departing load in their forecasts. There appears to be a dispute between PG&E and SSJID as to whether PG&E accurately accounts for departing load in their forecasts.

It is appropriate to give guidance here to clarify the IOU's obligations with regard to forecasting departing load as part of the bundled forecast. It is possible that there is a difference between the IOU's calculation of departing load and other objective measures of departing load, even after our decision in D.12-01-033. We require the IOUs, with information provided by the CEC and from other sources, to estimate reasonable levels of expected DA and CCA departing load over the 10-year term of the bundled plans. For CCAs specifically, the Commission has adopted an Open Season and Binding Notice of Intent (BNI) process to trigger the exclusion of potential CCA load from IOU bundled procurement. *See*, D.04-12-048, at 53-55 and Findings of Fact 27-29, at 201-202; D.0512-041, at 30-36 and Attachment B, as modified by D.06-02-006.

Once a CCA has submitted a BNI, its customers are no longer responsible for utility bundled procurement costs incurred after that date.

The IOUs should exclude this forecasted departing load from their future procurement activities, and only procure for the assumed amounts of retained bundled load. Having been excluded from the bundled portfolio planning scenarios, the forecasted departing DA and CCA load would not be subject to non-bypassable charges for any incremental stranded procurement costs incurred by the IOUs for the period after the date of departure assumed in their approved bundled plans.

Specific disputes, such as that raised by SSJID, can be litigated when an IOU files its bundled procurement plan, which will occur in the next LTPP proceeding.

5. Impacts of transparency on forward procurement

5.1. Question:

Should the Commission require the three major electric IOUs to provide more public transparency into the levels of future procurement for which each has entered into a contract? What confidentiality rules could be changed or removed? In particular how can IOUs provide visibility to the California Independent System Operator (CAISO) regarding their midterm procurement contracts?

5.1.1. Current Rules

The current rules governing confidential treatment of IOU data are set forth in D.06-06-066. Appendices 1 and 2 to D.06-06-066 provide rules for determining the confidential or public treatment for different types of utility and energy service provided (ESP) procurement information.[5] With regards bilateral or RFO-based procurement information, section VII subsections A and B specify treatment of information in contracts with affiliates and with non-affiliate market parties, respectively. Generally, pricing and contractual terms and conditions are confidential for three years. Other information such as identity of counterparty, location and name of generating facility involved, and megawatt (MW) size and length of contract (term in months or years) is public immediately. Pricing and market sensitive terms and conditions of contracts become public three years after first delivery under the contract.[6]

5.1.2. Parties' Positions

SDG&E and PG&E contend the question of whether confidentiality rules adopted in D.06-06-066 should be changed or removed is outside the scope of this proceeding. SCE does not support changing the Commission's current confidentiality rules, because they provide a sufficient level of transparency to the public and can adequately provide visibility to the CAISO.

IEP recommends that the IOUs clearly define the product they are seeking and should provide information about how certain characteristics of the product (or the developer, for some bid elements like viability or security) will be weighed in the evaluation process. IEP maintains that greater transparency about the prices of completed procurement will provide the market with the

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[5] D.06-06-066 is linked here: http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/57774.PDF

[6] Some fields in the matrix were modified by D.08-04-023, but not the two discussed in this section.

information it needs to respond to surplus (reflected in low prices) or scarcity (reflected in high prices).

Calpine believes information sharing regarding the IOUs' forward procurement plans is necessary but not sufficient to address the CAISO's intermediate-term reliability concerns. One function of a capacity market or other formal forward procurement obligation would be for the CAISO to validate forward procurement (*i.e.*, not only receive information about IOU procurement but ensure that the associated resources have tariff and/or regulatory obligations to be available and satisfy performance requirements).

WPTF concurs that greater transparency is needed with regard to the levels of future procurement for which each IOU has entered into contracts. WPTF believes such transparency, including in RFOs, will provide clearer signals to the market with regard to future planning and will enable prospective suppliers to better focus their future bid activities.

CCSF opines that the forward procurement process requires more transparency so that CCAs and ESPs can accurately assess the capacity and costs that will be assigned to their customers from past purchases. MEA encourages increased transparency in the IOUs' procurement. MEA states that its procurement information is publicly available and transparent, and the Commission should require that IOU procurement be similarly publicly available and non-confidential.

ORA believes the Commission should not require the IOUs to provide more public transparency regarding the levels of future procurement for which each has entered into a contract. ORA suggests the Commission pursue increased transparency by providing aggregated procurement data based on information gathered in the quarterly compliance reports, but not change or remove any existing confidentiality rules. ORA supports providing the CAISO with access to confidential information relating to the contract terms, pricing, and conditions of the IOUs' electric short, medium, and long-term procurement.

TURN agrees with the goal of providing the public more transparency as to the levels of future procurement. One step TURN suggests now is to aggregate the IOUs' procurement data along with those of other LSEs – to the extent they are knowable – and make this aggregated information public to the extent possible. TURN believes California would benefit greatly if the CAISO had more information about the IOUs' mid-term procurement activities and positions, particularly relating to those contracts that provide financial support to existing capacity.

Sierra Club believes agencies with regulatory obligations with respect to IOUs, such as CAISO and the Energy Commission, as well as the public, should have access to significant information about mid-term and other procurement contracts. CEJA urges the Commission to require further transparency within the procurement process to ensure the ability for meaningful public participation by communities affected by procurement. CEJA requests that the Commission require the disclosure of all non-confidential information submitted to the Procurement Review Group (PRG) to inform the public about RFO solicitations and evaluations. CEJA urges the Commission to increase transparency by making the environmental evaluation of projects in the RFO process publicly available, and to mandate disclosure of all bid evaluation criteria.

Clean Coalition supports the Commission's presumption that that information should be publicly disclosed. All pricing information for all power purchase agreements (PPAs) should be transparent to serve the interests of ratepayers. WEM feels that the most urgent need is for the Commission to pry open the utilities' near-absolute secrecy in regard to the distribution system, because almost all of the "distributed" preferred resources are attached to that system rather than transmission.

5.2. Question:

How can bids and offers RFOs are released publically? What other information could be released?

5.2.1. Current Rule

The current rules governing confidential treatment of IOU data are set forth in D.06-06-066. Appendices 1 and 2 to D.06-06-066 provide rules for determining the confidential or public treatment for different types of utility and ESP procurement information. Section VIII deals with the bid and valuation data produced by utilities and bidders in utility solicitations for capacity and energy. Bid data as well as other quantitative data of offer valuation is confidential for three years after the final winning bid is chosen and the contract is final.

5.2.2 Parties' Positions

PG&E does not believe disclosure of RFO bidding and pricing information is in the best interest of customers. PG&E believes the current amount of disclosure regarding RFO offers strikes the appropriate balance and no additional rules need to be adopted. SCE claims that bids and offers into RFOs are market-sensitive procurement information that is specifically protected under the IOU Confidentiality Matrix and therefore the Commission should not require it to be disclosed. SDG&E contends that the Commission had previously found that it is statutorily obligated to protect RFO bid data from disclosure.

IEP recommends that bids and offers submitted in IOU RFOs should be treated as confidential data to increase the level of competition and to promote innovation. Calpine opines that information should be made available so that market participants could replicate the market valuation and other components of the analysis and ranking of offers that the IOUs perform in their solicitations.

WPTF suggests that winning bid/offer information could be released five years after the fact on an anonymous basis that conceals the identification of the successful bidders. CCSF favors release of information to stakeholders about bids and offers into request for offers.

ORA recommends that bids and offers into RFOs should not be released publicly as the disclosure of bids and offers could negatively affect negotiations between the IOUs and power suppliers to the detriment of ratepayers.
Sierra Club recommends that this information be made public on the Commission website. The data should include bids, offers, price, volume, location, and date of delivery. Clean Coalition agrees that bids and offers into RFOs should be released online.

5.2.3 Discussion of Questions 5.1 and 5.2

The two preceding questions sought stakeholder input regarding whether to provide greater information to stakeholders, market participants, and other interested parties in California regarding utility procurement policies, recent procurement activities, and pricing and bid information. There appears to be two different types of information that are the subject of stakeholder interest: Utility procurement information, conducted either via bilateral negotiations or RFOs, and market participant bids and final contracts with pricing information or other terms and conditions that are market sensitive.

Section 454.5 (g) states:

> The commission shall adopt appropriate procedures to ensure the confidentiality of any market sensitive information submitted in an electrical corporation's proposed procurement plan or resulting from or related to its approved

> procurement plan, including, but not limited to, proposed or executed power purchase agreements, data request responses, or consultant reports, or any combination, provided that the Office of Ratepayer Advocates and other consumer groups that are nonmarket participants shall be provided access to this information under confidentiality procedures authorized by the commission.

The Commission has not to date allowed public disclosure of RFO bid and offer information, as such disclosure could reasonably be expected to affect the market to the detriment of IOUs and their ratepayers. Nothing has changed in this regard. We do not find it to be in the public interest to provide disclosure at this time. Certain providers of or advocates for preferred resources appear to believe they could benefit from disclosure of bid and offer (and other related) information, which may provide some advantage for such resources. The Commission has a number of policies in place and statutory requirements which provide avenues for additional preferred resources. It is more appropriate to pursue policies in these ways than to disrupt market functions through disclosure of currently confidential information.

Careful thought is required to balance the interest of market sensitivity of certain pricing and contractual terms between the utilities and their counterparties, with the benefits of increased transparency for market forecasting and procurement oversight. The market will benefit from greater reporting of procurement activity, particularly in the forward time frame where it is currently less open to the public.

The CAISO will also benefit from greater reporting of procurement information. The CAISO, as the entity responsible for ensuring reliable grid operation, must plan around which generating resources will be available to them and how those resources might operate. In the absence of contracts, there is reasonable uncertainty about which generating resources will continue to be operating and in what capacity within the energy market. The market behavior of individual generating facilities impacts planned operation of other facilities; information regarding which facilities were contracted (and which were not) is of importance to planning for grid operations in future years.

Therefore we intend to promote greater reporting of the information that the Commission regularly collects from the utilities, either as aggregate or in specific when advisable. As discussed at the November 14, 2013 Commission meeting, we intend to address issues related to providing the CAISO with access to certain utility contracting information in a related Rulemaking (the "Joint Reliability Plan" Rulemaking). Below in this decision we articulate a plan to reform certain data requesting guidelines, with an eye towards aggregating data via the quarterly compliance reports (QCRs) and reporting out that data in ways that are consistent and usable, while protecting market sensitive information.

In addition, the Commission is concerned that the non-disclosure agreements that the IOUs require bidders in their RFOs to sign have impeded the ability of market participants to bring concerns regarding the conduct of RFOs to the attention of the Commission and other state officials. While this Commission has no desire to be drawn into commercial negotiations regarding the prices and specific contractual terms and conditions being discussed between the IOUs and potential contractual partners, it is not in the public interest for parties participating in RFOs to be precluded from bringing more general concerns about the conduct of an ongoing or past RFO to the attention of the commission. Therefore, any non-disclosure agreement that the utility requires an RFO participant to sign must not bar the participant from reporting such concerns, nor may a utility arbitrarily reject the offer of a participant that engages in such a discussion with appropriate officials.

6. Long-term contract solicitation rules

6.1. Question:

Should the Commission adopt a rule that explicitly indicates that existing power plants may bid upgrades or repowers into new-generation RFOs?

6.1.1. Parties' Positions

PG&E states that RFOs for new generation (typically referred to as Long-Term RFOs) are generally designed to meet an incremental need for new system, local or flexible capacity. PG&E's position is that limitations regarding past long-term RFOs (only for new or repowered resources that are capable of addressing the incremental need) should remain in place, but existing facilities (including upgrades to existing facilities) should continue to be considered in short-term or intermediate-term solicitations. However, PG&E cautions that allowing existing resources to compete in new-generation long-term RFOs may lead to over-procurement, increased costs for customers, higher emissions, and/or a failure to meet the needs of the RFO.

SCE recommends that the Commission only allow capacity (whether developed at an existing power plant site or at a new site) that is incremental to what was assumed in the underlying "need determination" analysis to compete in "new generation" RFOs, so long as such incremental MW can provide the necessary attributes that the Commission has authorized the utility to procure. SDG&E does not object to allowing existing facilities to bid upgrades or repowers into new-generation RFOs. An existing facility may provide value to IOU ratepayers if it: (i) has a useful life extending beyond its current contract; or (ii) is able to lengthen its useful life by upgrading or repowering various facility components. SDG&E recommends that the Commission make clear that allowing upgrades or repowers to bid into new-generation RFOs does not change or override any additional requirements in an RFO such as locational requirements or operational characteristics.

IEP believes that distinctions among generating units based on age or vintage, or new vs. repower, are unnecessary in a product-oriented energy market. IEP recommends that if existing generators and repowers are excluded from bidding in long-term procurement solicitations, then a reasonable short- or medium-term capacity market (*e.g.*, 3-5 years) should be made available to these projects. Calpine recommends that the Commission reform long-term procurement rules to eliminate discrimination between different vintages of capacity. In addition, long-term procurement should focus on homogeneous products with uniform terms (*e.g.*, generic, local, or flexible capacity for 10-year terms).

AES Southland calls for the Commission to ensure that any upgrades or repowers that are bid into new generation RFOs result in additional incremental generation. AES Southland proposes that a generation project not be permitted to bid into a new generation RFO if that generation appears on the CEC's current California Power Plants Database of existing, operating plants in California as of the date of the RFO, except to the extent that the repower or upgrade would provide significant incremental capacity to the CAISO balancing authority area, either by expanding the generation capacity at a generation facility, or by extending the useful life of a generation facility, as a result of significant capital investment.

TAS Energy recommends adapting existing utility procurement rules to allow for retrofits including additions of energy storage systems to existing power plants by means of competitive procurement process such as requests for offers and bilateral contracts. CPV calls for IOU solicitations to be open to both existing and new generation to ensure that the broadest range of projects are afforded available commercial opportunities. The term of the contract should be commensurate with the needs of IOU but should also be influenced by the type of facility. An upgraded facility might only be eligible for a shorter duration contract relative to a repowered facility, while a new facility should be offered a longer term contract.

WPTF believes upgrades and repowers should be allowed to compete, just as any other way of meeting the RFO issuer's need should be permitted to participate. However, WPTF opposes the underlying implicit concept in the question that suggests that the utilities should conduct "new generation" RFOs. Rather, utilities should be required to issue RFOs for a need, whether that need is capacity, energy, ramping capability, location or a combination of some or all of these products. Any entity that can meet the need(s), as specified, should be allowed to bid.

ORA recommends that the Commission explicitly allow existing power plants to bid upgrades of those resources into new resource RFOs, providing that the quantity being offered is incremental to the existing rated capacity of the resource. TURN also recommends that the Commission should facilitate the IOU competitive contracting for upgrades or repowers of existing power plants.

Sierra Club recommends that the Commission make a distinction between a long-term repower and an upgrade that may provide a relatively short-term capacity fix while California transitions to low carbon future. CEJA urges the Commission to adopt a rule that explicitly indicates that existing power plants may bid upgrades or repowers into new-generation RFOs. GPI suggests the

Commission's singular goal in this particular kind of solicitation should be in procuring the lowest-cost energy possible. This means that the offers need to be refocused from their present orientation to the machinery that produces the needed product, to instead focus squarely on the needed products themselves, regardless of how they are produced.

6.1.2. Discussion

Most parties recommend that the Commission allow certain upgrades and repowers to bid into long-term RFOs. While current rules do not specifically prohibit the combination of RFOs for existing or new facilities, we hereby clarify that certain upgraded and repowered plants are allowed to bid in new generation RFOs. We clarify the rules so as to oversee the administration of RFOs that fill defined reliability needs in the most cost effective way.

Allowing for the incremental capacity of existing plants or repowered plants to participate in long-term RFOs appropriately acknowledges the varied technological capabilities and improvements possible with today's generation stock, and may alleviate some need to build additional capacity. In addition, it may be possible for an existing power plant to add capabilities (*e.g.*, energy storage, more optimal ramp rate, or start up times) that would enhance the operation of the plant and increase its value to the system.

In discussing this issue, first we need to define the term "incremental capacity." We will take SCE's recommendation that the definition should be "capacity incremental to what was assumed in the underlying needs assessment." In other words, these are net additions. We agree with SDG&E that an existing facility may provide value to IOU ratepayers if it has a useful life extending beyond its current contract or is able to lengthen its useful life by upgrading or repowering various facility components. The following terms are defined herein:

- Upgraded plants: Upgrades are defined as expanding the generation capacity at, or enhancing the operation of, a generation facility, so long as such incremental MW can provide the necessary attributes that the Commission has authorized the utility to procure. An upgraded plant or a plant with incremental capacity additions would be a plant where the main generating equipment is retained and continues to operate.
- Repowered plants: Repowers are defined as capital investments that extend the useful life of a generation facility, after the planned retirement date. A repowered facility is a facility where the main generating equipment (such as the turbine) is changed out for new equipment.

Parties want to ensure neutrality between types of facilities that are competing against one another in a solicitation for capacity. Some parties doubt that utilities define capacity needs specifically enough to ensure that valuations can be neutral with regards whether the offered product meets the identified needs. We urge the utilities to remove whatever ambiguity or lack of clarity there is in RFO documents, so as to ensure that bidders know which services, quantities, or locations are the target of the RFO. While we are unaware of specific examples in this proceeding of RFOs that cause bias towards or against a type or vintage of facility through lack of clarity in bidding documents or bid valuations, parties are encouraged to bring complaints to the attention of Energy Division for investigation.

6.2. Question:

How should the existing and upgraded components of the repowers be valued differently in an RFO? How can additions such as energy storage be added to existing facilities and be valued against other types of offers?

6.2.1 Parties' Positions

PG&E suggests the same principle should apply to energy storage that is incorporated into repowers and upgrades of existing facilities. If the storage technology results in a facility with a remaining useful life equivalent to a new resource, it should be eligible to compete through a long-term RFO. SCE recommends that only the net additions to what was assumed in the underlying need determination analysis would be eligible to be counted towards meeting the identified need. Once the generation is found to be eligible to participate in the new generation RFO, SCE plans to apply the same valuation and selection methodology to all eligible generation that can fill the identified need (*i.e.*, provides the necessary attributes that SCE is seeking via its new generation RFO). SCE plans to value any energy storage additions proposed at existing facilities in a similar manner to all other new resources that it procures. SDG&E comments that upgrades and repower proposals do create some complexity in the evaluation, but the product they provide should be valued no differently than any other offer.

IEP believes the answer to the question depends on if the Commission develops a product-oriented procurement model to disaggregate the cost basis of unit bids. Competition among those that can provide the products or services requested will reveal the value in the first case, whereas the second case requires a much broader discussion. The simplest and most useful tool for determining the benefit associated with energy storage is to have transparent, time-of-delivery factors applied in bid evaluation so that bids are valued based on their ability to deliver (or absorb) energy when needed and subject their facilities to economic dispatch. Calpine recommends that the existing and upgraded components of a facility not be treated differently in long-term solicitations.

AES Southland suggests that the Commission should not use different evaluation methodologies for determining the value of existing versus upgraded components of repowers in an RFO. Instead, it should strive to develop a generally applicable set of bid evaluation metrics that would allow the utilities, and the Commission, to quantify the benefits of upgraded or repowered generation as compared to new generation. Like upgrades and repowers, storage additions should be evaluated pursuant to a general set of evaluation metrics that would allow the Commission and utilities to compare the benefits of storage additions to other solutions to energy and capacity needs.

TAS Energy recommends that, as these cost savings would be reflected in the bid, retrofits should be valued comparably with other resources accordingly. In the case that the retrofit is an energy storage system, it would be consistent with other proceedings and determinations for this system to be evaluated along with other cost-effective preferred resources including energy storage resources. CPV recommends that the attributes and associated cost of the aggregate generation (rather than its components) should be the driver in the RFO, and evaluation of storage should be no different than that of generation.

CESA recommends developing a means to transparently value the addition of storage to existing generation facilities, by measuring the value of adding capacity or economic value via competitive procurement process such as requests for offers or bilateral negotiations. CESA states that it is imperative to ensure that additions and retrofits are able to participate in the RFO process are explicitly stated to be eligible be included in RFO's, and that power plants then currently under contract would not have their existing contract reopened to account for the new investment in additions or retrofits to the power plant. Rather, a separate overlay contract could be offered to the entity bidding the addition or retrofit project for investment, separately from the existing power plant's existing contract or contracts.

WPTF contends this question confuses need with the method of meeting the need. WPTF believes that repowers should not be valued "differently." Rather, a proposal that includes repowers should be evaluated as to whether or not the proposal does or does not meet the technical needs, as described in the RFO. The same principle should apply with regard to energy storage offers.

ORA notes that resolving issues and developing uniform guidelines for evaluating incremental upgrades would take significant time. ORA in the interim supports providing the IOUs a degree of flexibility to address these evaluation challenges. ORA recommends that energy storage arising from new investment should be valued as a new resource so that it can be bid into a long-term RFO, whether it is located at an existing facility site, or elsewhere.

Sierra Club opines that repowers of fossil fuel plants should not be valued differently, but upgrades should be valued for the role that the upgrades will play in the system. If an upgrade provides short term value that facilitates the opportunity for more preferred resources to be placed on the system, it should be a given a value for this function. Similarly, energy storage should be valued for the additional benefits that it can provide to the system that are not typically valued in the current RFO process, and that are environmentally and operationally superior to the performance of natural gas plants. CEJA recommends that RFOs should allow consideration of energy storage constructed at existing facilities because it can provide additional flexibility and ancillary services.

6.2.2 Discussion

As the responses indicate, this is a complex issue. At this time, we find it to be unnecessary or premature to decide on any new or different valuation for repowers or upgrades in long-term RFOs. In particular, as the energy storage industry develops further, it may be appropriate to develop new valuation rules for such technologies. But we have too little knowledge or information about this fledgling industry to come to any conclusions at this time. However, we do wish to clarify that an offer of incremental capacity should be evaluated based on the cost and value of the incremental capacity alone, and not some combination of the existing and incremental capacity of the unit in question.

6.3 Question:

Should contracts for repowering or upgrading of facilities be restricted to the same length of contracts as new facilities? If not, please explain why there would be different contract lengths or different terms, and how these differences would be reflected in the valuation of the bids.

6.3.1 Parties' Positions

PG&E contends the investment and risk criteria for a retrofit or upgrade to an existing resource is substantially less than for a new or repowered resource. Thus, PG&E believes contracts for existing facilities, including facilities that have incremental upgrades, can be shorter in duration than a contract for a new or repowered resource. SCE plans to apply similar terms and conditions to all eligible generation that can fill the identified need and provide the necessary attributes. SCE does not plan to offer different lengths of contracts to incremental generation as a result of repowering or upgrading of facilities than what it would offer to new facilities. SDG&E recommends that contract term length for repowered or upgraded facilities should be restricted to the remaining useful life of the overall asset.

IEP contends the length of the contract should be determined more by the identified needs of the IOU than by the nature of the offered resources. IEP recommends that bidders of all types, including repowered or upgraded facilities, should have an equal opportunity to bid varying terms of service in response to the IOU's defined needs. Calpine believes that, to the extent that a resource is able to satisfy the defined need, the resource should be able to participate in the resource solicitation regardless of the vintage and/or type of resource.

AES Southland recommends that a repowered or upgraded facility bidding into a new generation RFO should be restricted to the same length of contracts as new facilities. However, AES Southland suggests that RFOs provide a range of minimum and maximum acceptable terms that both new generation and repowered generation could bid into the RFO, and that generation should be permitted to bid more than one term option into the RFO as well. TAS Energy recommends that contracts for repowering or upgrading of facilities should receive the same restrictions and guidance as all other new facilities, with no difference in the length of contract offered. CPV recommends that the IOU's solicitation should specify a minimum and a maximum term into which bidders can exercise their judgment on what makes the most sense for their project.

WPTF does not support narrowly contracting for new resources, repowers or upgrades specifically, but supports the principle that new, repower and upgrade proposals be treated indiscriminately. The Commission can provide clarity by defining contract minimum and maximum terms so that projects can bid in at varying terms with different price structures.

ORA supports flexibility in contract terms that would allow full resource participation and give IOUs the ability to determine which resources best adhere to the least-cost best-fit evaluation criteria. Sierra Club suggests that contracts for upgrades can be for a more limited duration. CEJA opines that contracts for upgraded or repowered facilities should be allowed to bid for different length contracts. GPI states there is no reason to impose different rules or restrictions on facilities just because they are upgrades or repowers of existing facilities.

6.3.2 Discussion

Currently, there are no restrictions on contract lengths for new facilities. We are not convinced that there is any purpose at this time to constrain contract lengths for IOU contracting for upgrades and repowers, as compared to other new resources. Contracts for upgrades or repowers that meet our criteria should be allowed to bid for different lengths of time. The IOU can evaluate such bids based on its needs.

6.4 Question:

Is there any information (additional or subtracted) from the RFO or application templates that would need to be changed? Would Energy Division review the RFO differently?

6.4.1 Parties' Positions

PG&E opines that protocols may need to be changed for future RFOs, and to some degree, application templates. The portions of the protocols that may need to be amended include eligibility requirements and contract options, both of which are dependent on the identified procurement needs for a future solicitation, especially taking into consideration whether the need is longer-term versus short- or intermediate-term. Also, future solicitations should be specific regarding the operational characteristics that a portfolio of procured resources is required to have.

SCE suggests the Commission does not need to change the RFO process or the RFO approval application templates to allow upgrades at existing power plants or repowered sites to compete in new generation RFOs. SDG&E agrees that the RFO application and templates do not require amendment, except to add clear definitions for the following terms: upgrade, repower, and energy storage, and that no change to the Energy Division's current RFO review process is necessary.

IEP suggests that to the extent that a minimum or maximum term of service is desired, the minimum/maximum must be prescribed in the RFO. Additionally, the eligibility requirements for bidders must be clear. AES Southland suggests that the Commission require utilities to develop a robust list of evaluation metrics that should be expressly set forth in each RFO. In turn, those metrics should be evaluated in any application submitting a contract from that RFO to the Commission for approval.

TAS Energy advocates that the RFO process explicitly include a provision that assets currently under contract would not have their existing contract reopened to finance investment in new generation through upgrades to the site. Rather, a separate contract, or overlay contract must be offered to the entity bidding the retrofit/upgrade project for such investment, separately from the existing site's operating contract. CPV recommends greater flexibility as to type of generation and term ought to be added to the RFO process.

6.4.2 Discussion

There is no clear reason to change any aspect of the RFO process or application template at this time as a result of our allowing bids for repowers or upgrades. If any changes become necessary, they can be undertaken through Energy Division.

6.5 Question:

How should cost allocation issues be addressed?

6.5.1 Parties' Positions

PG&E contends that, to the extent that an upgraded or repowered facility provides system or local benefits, the costs and benefits associated with the facility should be allocated to all benefitting customers (*i.e.*, bundled, DA and CCA). SCE argues that the Commission's current CAM rules should continue to apply to procurement of all new resources authorized by the Commission for system or local area need. SDG&E recommends that if an upgrade or repower of an existing power plant is bid into a new-generation RFO and the Commission determines that the resource is needed to meet local or system area reliability needs for the benefit of all customers in the IOU's service area, the total capacity cost of the repowered or upgraded resource should be allocated to all benefitting customers through the CAM established pursuant to § 365.1(c)(2).

Calpine opines that if suitable forward RA procurement requirements that apply to all LSEs are implemented, then the resulting forward RA market, whether bilateral or centralized, would allocate the cost of forward capacity procurement, regardless of whether the capacity is new, existing, upgraded or repowered. In contrast, to the extent that the IOUs undertake forward procurement on behalf of all customers, not only bundled customers, the cost of such procurement would be recovered through non-bypassable charges.

AReM/DACC recommends that the Commission should insist that the costs of all such upgrades and repowerings are to be recovered solely from the bundled load customers who require these plants to serve their load.

MEA suggests that preexisting facilities which have undergone an upgrade or repower should not be considered for CAM treatment. Sierra Club contends that cost allocation issues should be addressed in a separate proceeding that addresses the costs of all procurement mechanisms at the same time.

6.5.2 Discussion

This decision addresses CAM issues beginning in section 8.

7 Specification of the Rules that, if followed, would allow the IOUs to execute bundled procurement contracts with specified additional review by the Commission[7]

7.3 Question:

Please comment on the following potential new or modified rules to ensure competitive bundled procurement transactions:

1. The IOUs must submit an advice letter or application if they follow their established AB 57 bundled procurement plan authorization, and:
   a. The contract unit price is a higher than a particular percentage (such as 80%) of the CAISO Capacity Procurement Mechanism or other administratively or market established price,
   b. The RFO did not attract sufficient participants, or
   c. The total MW procurement is over a specified level of MW.

7.3.1 Parties' Positions

PG&E contends that rules requiring added review and approval by the Commission would be duplicative, add significant delay to the procurement process, increase procurement costs, and could affect the reliability of the electric

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[7] For clarification purposes, the wording of this section title is slightly different from the wording of the associated question in the Ruling.

system. SCE claims that requiring an advice letter or application, even though an IOU has met its AB 57 bundled procurement plan upfront standards and criteria, would erode that statutory framework. SDG&E claims the proposal violates AB 57 and is contrary to Commission precedent. SDG&E believes the rules currently in place effectively ensure that IOU transactions are reasonable and there is no demonstrated need for the new rules proposed.

MEA does not support these modified rules unless such transactions are excluded from stranded cost treatment; *i.e.*, no costs associated with such transactions would be paid by CCA customers. ORA disagrees with this proposal to reduce the amount of oversight over individual procurement contracts to streamline the contract approval process.

Sierra Club argues that creating mechanisms that reduce the ability of the Commission and the public to review action approved by the Commission reduces the Commission's ability to provide effective oversight. CEJA urges the Commission to not reduce oversight of bundled procurement contracts.

7.3.2 Discussion

Medium-term contracts are contracts of three consecutive months or greater and under five years in duration. Long-term contracts are contracts of five years or more in length. Long-term contracts must be submitted with an application to the Commission for preapproval, whereas short-term and medium-term contracts do not need preapproval. We currently do not impose oversight via advice letters over medium term contracts except for contracts with OTC units. Per D.12-04-046, PPAs with OTC plants with contract duration of greater than two years must be submitted to the Commission's via a Tier III advice letter.

We find there is a gap in Commission oversight. By providing utilities and counterparties with little scrutiny of contracts of significant size with large cost implications, this gap exposes ratepayer to more risk than is appropriate. We conclude that we should impose greater oversight of medium term bilateral contracts. Utilities will now be required to submit Tier II Advice Letters seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 megawatts. This rule is in addition to all previous procurement rules.

We also clarify rules for certain multiple contracts. For the purpose of medium term and long term contracts, multiple contracts entered into at the same time for the same resource and for consecutive time periods are considered one contract and may not be treated as different transactions for Commission approval. More specifically, for the purpose of determining the "term" of a contract, two or more contracts, including contractual options, are treated as one (linked), where:

a. They specify the same resource as the primary delivery source or, (2) for an unspecified source, they are with the same counter-party; ***and***
b. They are negotiated or executed within any three consecutive month period, except if entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final).

D.03-12-062 granted authority for the use of negotiated bilateral contracting in three limited circumstances. One of these circumstances is that an IOU may use negotiated bilateral contracts to purchase longer term non-standard products provided it justifies why a standard product that could have been purchased through a more open and transparent process was not available or in the best interest of ratepayers. The Commission has refrained from broadly defining non-standard products; however, the intent of the Commission and language of Public Utilities Code Section 454.5(B)(5) was to give utilities flexibility in procuring products only in cases where they are difficult to procure via a competitive solicitation. We understand that products like RA capacity and energy tolling are widely available and are not difficult to procure via a competitive solicitation. Therefore, the utilities should treat RA capacity and energy tolling as standard products and reflect this in their AB 57 bundled procurement plans.

7.4 Question:

Should the Commission impose this rule: Any bilateral contract for a facility that did not make the shortlist of an RFO or an offer that has subsequently been negotiating with the utility for longer than six months since making the shortlist of an RFO must seek Commission approval through a Tier III advice letter or application.

7.4.1 Current Rule

D.03-12-062 granted authority for the use of negotiated bilateral contracting in three limited circumstances.

1. For short-term transactions of less than 90 days duration and less than 90 days forward, the IOUs are authorized to continue to use negotiated bilaterals subject to the strong showing standard.
2. Second, utilities may use negotiated bilateral contracts to purchase longer term non-standard products provided they include a statement in quarterly compliance filings to justify the need for a non-standard product in each case. The justification must state why a standard product that could have been purchased through a more open and

transparent process was not in the best interest of ratepayers.

3. Third, IOU authority is expanded for use of negotiated bilaterals for standard products in instances where there are five or fewer counterparties who can supply the product. This authority is limited only to gas and pipeline capacity.

D.04-07-028 at 17 added one more circumstance: "In addition to the limited circumstances enumerated in D.03-12-062 at Conclusion of Law 15, we authorize the utilities to engage in bilateral negotiated contracts for capacity and energy from power plants where the purpose is to enhance local area reliability."

7.4.2 Parties' Positions

PG&E argues that this proposed rule is unnecessary because current procurement rules significantly limit bilateral transactions and generally would not allow a bilateral transaction with a facility that did not make the shortlist of an RFO (outside the existing 30 day post-RFO limit). SCE contends that direct bilateral contracting is already appropriately restricted in the IOUs' AB 57 bundled procurement plans. SDG&E contends that the proposed rule is arbitrary and unnecessary, and would create administrative burden.

IEP agrees with the idea that bilateral contracts for a facility that did not make the shortlist of an RFO, as well as bilaterals selected outside of competitive processes, should be subject to the greater scrutiny of a Tier III advice letter or application. WPTF argues that the Commission should be reluctant to approve bilateral contracts that are untested through a competitive solicitation.

ORA does not support this proposal, stating that it is unclear how this proposal would enhance the current IOU contract review process and what improvements this makes. Sierra Club supports requiring an application in this situation to ensure oversight of the bilateral contract.

7.4.3 Discussion

We are not persuaded that additional procurement oversight is warranted based on the triggers suggested in the question. We agree with the utilities in that additional triggers for oversight may not be supportable at this time, and would be duplicative or redundant given the intent of the procurement rules the Commission imposes. We will not impose restrictions of this nature or create oversight triggers of this nature at this time.

7.5 Question:

What rules are needed to determine whether an IOU transaction is reasonable and therefore does not require additional review and Commission action?

7.5.1 Parties' Positions

SCE claims that all of the existing rules have been in place for several years and are working very well, thus no other rules are needed to determine whether an IOU's bundled procurement transaction is reasonable. SDG&E and PG&E agree that current rules are sufficient and no new rules are required.

IEP argues that contracts that are not the result of a competitive procurement process should be subject to greater scrutiny. WPTF states that the simplest test of reasonableness is to conduct a competitive solicitation, which by definition should result in reasonable IOU transactions.

MEA believes the Commission should review and approve any IOU transaction with a term of 12 months or longer and any transaction that could impose costs on CCA customers. ORA recommends that the Commission's Least Cost-Best Fit methodology and approval of the IOUs' bundled procurement plans should continue to be used as guidelines within the context of an advice letter or application to determine whether an IOUs' procurement transaction is reasonable. ORA does not support making exceptions to these rules that would further reduce the Commission's oversight or the up-front review process of each procurement transaction.

7.5.2 Discussion

We agree with parties who contend that current rules for determination of reasonableness of utility transactions are sufficient and not in need of revision.

8 Cost Allocation Methodology (CAM)

8.3 Questions:

The following questions related to the CAM were asked in the ALJ Ruling:

1. Is the CAM currently implemented in a manner that is sufficiently transparent or least cost?
2. Should the Commission reform the CAM energy auctions? If so, how?
3. How does the capacity allocation interact with other allocated costs such as energy efficiency and demand response funding?
4. At what stage in procurement should procurement be deemed CAM eligible, and what criteria should govern Commission decision regarding CAM allocation?
5. How should the Commission address flexibility in regards to the CAM? For example, should resources built in one IOU's service territory spread costs across all the California Public Utilities Commission's jurisdictional load-serving entities?
6. Should the CAM rules be differentiated to best account for benefit and cost allocation among community-choice aggregators and electric-service providers, based on their different business models or portfolio of other contracts? If so, how?

8.3.1 CAM Overview[8]

D.06-07-029 in the 2006 long-term procurement proceeding decision adopted the CAM, which allows the costs and benefits of new generation to be shared by all benefiting customers in an IOU's service territory. The Commission designated IOUs to procure the new generation through long-term PPAs, and the rights to the capacity were allocated among all LSEs in the IOU's service territory. The allocated capacity rights can be applied toward each LSE's RA requirements. In exchange for those benefits, the LSEs' customers – termed "benefitting customers" – pay for the net cost of the capacity.[9]

The basic framework for the CAM was set forth in D.06-07-029 as follows: The IOU would contract with an Independent Evaluator to oversee an RFO for new resource contracts. At the conclusion of the RFO, the IOU would sign a long-term contract with the generator of a new resource. The IOU would seek contract approval from the Commission, and at that time, select whether or not it intends for the CAM to apply to the contract. The Commission's decision on the IOU's application determined the applicable CAM based on allocating the appropriate net capacity costs to all benefiting customers in the IOU service area.[10] The IOU would then request Commission approval to conduct periodic auctions with an Independent Evaluator for the energy rights of the resource,

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[8] Portions of this overview are taken from D.13-02-015 at 98 – 100.

[9] The energy and capacity components of the newly acquired generation are disaggregated. The net capacity cost is calculated as the net of the total cost of the contract minus the energy revenues associated with the dispatch of the contract. The non-bypassable change levied is for the net capacity cost only, and the non-IOU LSEs maintain the ability to manage their energy purchases.

[10] D.06-07-029 at 52-53.

essentially selling the tolling right – the energy component – and retaining the RA benefit, which it then shares with all customers paying for the capacity.[11] D.06-07-029 at 26 explained that "benefiting customers" referred to all bundled service, DA, CCA customers and "other customers who are located within a utility distribution service territory but take service from a local publicly-owned utility subsequent to the date the new generation goes into service." D.06-07-029 at 26 (footnote 21) specified that current customers of publicly-owned utilities were exempt from the CAM.

Subsequent decisions clarified and amended the CAM. D.07-09-044 presented in greater depth the procedures for the energy auctions. The procedures established a backstop for the auctions. Should an auction fail to produce a successful bid for the energy products, the capacity costs would be calculated via a specified alternative mechanism.[12] D.08-09-012 set forth that customer generation departing load was exempt from the CAM. That decision clarified that only large municipalizations were subject to the CAM, while exempting other classes of municipal departing load.

SB 695, signed into law in 2009, requires that the net capacity costs of new generation resources deemed "needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory" must be passed on to bundled service customers, DA and CCA

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11 D.06-07-029 at 31-32.

12 *See* D.07-09-044, Appendix A for specifics relating to the Joint Parties' Proposal, the alternative to the auction mechanism.

customers.[13] In order to align the CAM with the requirements of SB 695, D.11-05-005 did the following:

a. Removed the right for the utility to elect or not elect CAM treatment for a resource that meets the conditions of the statues;

b. Widened the scope of the CAM to apply to UOG resources; and

c. Extended the duration of CAM treatment to match the duration of the underlying contract, eliminating the 10-year cap.[14]

SB 790 in 2011 codified the Commission requirement that the costs to ratepayers for CAM procurement must be allocated to ratepayers in a "fair and equitable" manner.[15]

Currently there are several different ways that utilities procure capacity on behalf of the customers in their service territory, both bundled and unbundled. There are demand response programs, which are funded and administered by the utilities, and whose costs are allocated to all distribution level customers in their service territory. This is done in light of the fact that all customers in their service territory may participate, and all customers in their service territory may enjoy the grid reliability benefits of these demand response programs.

Separately, the Commission created a CAM mechanism for new generation that is constructed pursuant to the LTPP for grid reliability. Finally,

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[13] Stats. 2009, ch. 337.

[14] D.11-05-005 reaffirmed that SB 695 does not require any revisions to the determinations made in D.08-09-012 regarding non-bypassable charges and the CAM process.

[15] Stats. 2011, ch. 599.

the CHP settlement adopted in 2011 required the utilities to procure CHP facilities to create the benefits of GHG reduction enjoyed by all customers in their service territory. The net capacity costs of CHP procurement are also allocated to all customers in their service territory. From time to time the Commission also requires the utilities to procure facilities under special circumstances.

The Commission administers a variety of centralized procurement programs, each with impacts to bundled and non-bundled benefitting customers. The Commission may create more programs of that nature in the future, and allocate further costs to benefitting customers. No Commission determinations have been made as to how the different types of centralized procurement (CHP procurement, demand response, new generation resources pursuant to LTPP, and the recently approved energy storage procurement mandate) relate and how all these types should be evaluated in combination with the goal of providing cost effective reliability and adherence to the Commission's Loading Order.

Pursuant to D.12-06-025, Ordering Paragraph 4, LSEs are differentiated in terms of coincidence adjustment based on types of load served or load shapes. Therefore, the determination of LSE RA obligations is already differentiated between types of LSEs. In terms of CAM, the LSE's proportionate share of CAM capacity allocation depends on their forecasted peak load (with coincidence adjustment) relative to service area peak. Thus there is a slight differentiation among LSEs with regard to each LSE's CAM capacity allocation. D.12-06-025 determined that LSEs contributed to reliability need (and thus RA obligations) individually relative to the load profiles of their individual customers.

In D.13-02-015, we discussed a number of proposals by parties to make significant changes to the CAM, but declined to do so at that time. In the record of this proceeding (both Track 1 and Track 3) several parties question how the Commission makes determinations of CAM eligibility and how costs are allocated to customers. Many parties also question under what conditions the Commission should determine that a particular procurement activity creates benefits for customers.

The Commission has broadened the application of CAM considerably in recent years. As new facilities authorized under CAM have come online, the costs and CAM capacity benefits have burgeoned in recent years. In 2007, less than 500 MW of capacity were allocated via the CAM; by 2013, approximately 5000 MW were allocated through this mechanism. This figure is expected to increase to around 9000 MW by 2018.[16]

8.3.2 Parties' Positions

Overall, the utilities unanimously oppose significant changes to most CAM-related issues, other parties continue to propose innovative alternatives to perceived inequities in the current CAM process. TURN does not see any positive value in revisiting CAM issues at this time.

AReM/DACC states that they have a significant concern that all ratepayers -- including DA and CCA customers who must pay for CAM projects, energy efficiency and demand response programs -- are being double charged when utility procurement authorizations are predicated upon forecasts that presume energy efficiency and demand response will not make the expected contribution to load reductions. AReM/DACC also suggests that another element of CAM flexibility the Commission should consider would be to afford

[16] *See* the Commission's posted Final 2014 CPUC Net Qualifying Capacity list.

ESPs and CCAs the opportunity to self-fulfill their System or Local reliability needs and avoid CAM charges based on IOU procurement.

AReM/DACC recommends that the Commission should direct that: 1) procurement required to meet bundled customer needs is not subject to the CAM; 2) the only procurement that may be afforded CAM treatment is that which is specifically ordered by the Commission for reliability purposes and that has been demonstrated to benefit all customers; and 3) determination of whether customers who are served by ESPs or CCAs receive any benefit from IOU procurement must include an assessment of whether the customer's competitive supplier is already providing reliable service to those customers and meeting all the regulatory and system requirements as a load serving entity.

AReM/DACC argues that there is no process for distinguishing between system and bundled resource needs, nor a realistic test to determine who benefits from IOU procurement, as required under SB 695 in order for CAM to be used at all. AReM/DACC proposes to give the PRG and the CAM Group greater authority to reject utility procurement that is not economic or that does not represent the least-cost option for all ratepayers.

CCSF does not support having bundled customers or CCA distribution customers of one IOU be subject to CAM non-bypassable charges from procurement by another IOU. CCSF argues that the Commission has failed to precisely define the standard for CAM set forth in Section 365. l(c)(2)(A), thus allowing the lOUs to interpret the statute to support CAM for any resource that provides any degree of reliability.

SSJID contends that municipal departing load should be exempt from all CAM allocations because POUs develop and procure resources to meet the requirements of their own customers, and such resources provided by POUs have system-wide benefits equivalent to IOU-developed and procured resources. SSJID argues that charging municipal departing load for IOU capacity costs without charging IOU customers for capacity developed by the municipal departing load's Public-owned utility(POU) service provider is contrary to the Commission's indifference principle because it results in bundled customers benefiting from municipal departing load and ensuing POU capacity development.

WPTF believes that resources should be evaluated for CAM eligibility on the basis of its primary purpose. That is, if the resource was added primarily to provide supply to bundled customers, then the tangential reliability improvement should not be sufficient to justify CAM treatment. Further, WTPF argues that there is an urgent need for the Commission to develop specific criteria by which competitive suppliers are deemed to have met the reliability needs of the customers they are serving such that IOU procurement on their behalf is unnecessary and of no benefit to them – and therefore exempt from any CAM allocation of costs or net capacity.

MEA argues that the Commission must propose a clear methodology for determining the "fair share" of CAM benefits and costs so that customers of a CCA are not subjected to paying over-procurement costs. MEA recommends that the Commission determine specific reliability (operational and locational) needs which, if a resource filled such a need, would meet the CAM eligibility requirements in the Long Term Procurement Plan proceeding. This determination would be made prior to the evaluation of any specific facility. To reach this determination, MEA proposes that the Commission must evaluate the current status of RA in each of the IOUs' footprints using the following method:

- First, the Commission would undergo an analysis of unmet needs.
- Second, the Commission would determine the drivers of the unmet need; for example, if retirement of utility controlled generation is the driver of a need, then the IOU would be responsible for that procurement.
- Third, the Commission would take the remaining unmet need and offset it against known RA contracted resources which may be held by IOUs or other market participants.
- What would remain is a unique RA attribute or various unique RA attributes which are not met by existing RA rules, and which is not driven by bundled load. This is the CAM-eligible need. The CAM-eligible need should be clearly specified in MW or a range of MWs, and the RA attribute which would meet the CAM eligibility requirements.

MEA argues that the CAM should not reach beyond the footprint of a given IOU. MEA states that both energy efficiency and demand response have impacts on the RA needs of a LSE, both from a peak load perspective and from an average demand perspective. MEA notes that under the energy efficiency model, it is understood that any entity providing energy efficiency programs provides a benefit to all customers. MEA sees CAM as a one-way street, where an IOU's procurement can "benefit all customers" but the CCA's procurement which also benefits all customers is not acknowledged under the current methodology.

MEA proposes two alternatives:

1) Each LSE is required to procure its own RA in accordance with Commission-mandated requirement and no LSE is allowed to allocate those costs to another LSE unless an exigent circumstance arises; or
2) To the greatest extent possible, any CAM allocation of IOU procurement is offset, in the case of CCAs, with

> procurement undertaken by the CCA and the value that procurement provides. To accomplish this, the Commission could adopt an optional mechanism for CCAs who are willing to provide additional documentation to the Commission such as through an advice letter filing so that the CAM cost and capacity allocation could be offset by the CCA's own procured resources. MEA believes an optional mechanism is appropriate in order to respect jurisdictional authority and CCA procurement autonomy.

MEA also recommends allowing for third party demand response and energy efficiency resources to compete in an all-source request for offers to fill the identified CAM resource need.

ORA supports a process by which the Commission should assume sufficient preferred resources will materialize to meet system and local area need rather than not, and direct the IOUs to develop their preferred resource programs in a manner that will produce those results. Reduction of the need for new system and local area reliability resources through EE and DR procurement will minimize CAM procurement. ORA recommends that the Commission direct the IOUs to work with CAISO to determine a priority ordered listing of the most electrically beneficial locations for preferred resource deployment (supply or demand side) in a systemic way to maximize these resources' ability to reduce system and local area need. For local capacity requirements (LCR), such a listing should use a reasonable level of electrical aggregation—at the very minimum the LCR sub-area or if possible, a finer electrical-location granularity such as substations.

8.3.3 Discussion

In D.13-02-015, we considered potential changes to the CAM energy auction. At that time, we found: "The record does not provide an adequate and persuasive basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism." (D.13-02-015, Finding of Fact 53.) With the additional comment in this Track of the proceeding, we are now prepared to act on this issue. We will now eliminate any requirement that a utility undertake a CAM energy auction as a tool to net capacity costs for CAM facilities.

For reasons of transparency and accuracy, parties' comments largely recommend removal of the CAM energy auction. While there may be benefits to such energy auctions (*e.g.*, the hedging benefits of longer term tolling agreements relative to the short term JPP), there are also benefits to having shorter term ways to net capacity costs if situations change.

We are concerned with protecting all ratepayers, and need to ensure that all ratepayer groups (including DA and CCA load) are treated equally. This is the reason that the CAM was developed in the first place – to ensure that all ratepayer groups were treated equally. We conclude that it would be unfair to create a system that allows one ratepayer group to allocate costs to other ratepayers when there is reason to believe that those costs are not sufficiently justified or that the costs are likely to mismatch actual market value.

While the JPP might arrive at costs that are not always indicators of real value, given the complexity of the CAISO markets, the mechanics of the JPP allow for a forecast and a true up later. On the other hand, the energy auctions arrive at the highest bid, regardless of future energy prices, and there are insufficient safeguards to ensure that the final award is accurate or that the auction itself is fair and robust. There are elements of the auction that may not present true equality between bidding parties. It is also unclear if the tolling agreements that result from the energy auctions abide by the CAISO tariff or allow for implementation of CAISO tariff the way a toll with the original purchaser would. For example, requirements for generators to submit economic bids to count for flexibility for can be problematic when the owner of the plant sells a tolling agreement, where the purchaser might not be the scheduling coordinator. The replacement requirement for RA resources that take planned maintenance may lead to compliance problems when the facility is not scheduled by the same party that owns the tolling agreement.

For these reasons, we remove the requirement for an energy auction as a tool to net capacity costs for CAM facilities, and instead require all utilities to utilize the mechanism adopted in the JPP to set the residual capacity costs that would be allocated to benefitting customers.

8.4 Question:

Should the Commission reform the CAM energy auctions? If so, how?

8.4.1 Current Rule

Pursuant to D.07-09-044 and the Joint Party Proposal (JPP) adopted in that decision, utilities have a choice to use the energy auction or a mechanism that relies on MRTU for energy pricing to set the energy revenue which would debit against contract costs to create the net residual capacity costs for allocation under the CAM. The JPP mechanism for calculating net capacity costs outlines the principles to be applied in energy auctions used to determine net capacity costs.

8.4.2 Parties' Positions

PG&E recommends that the energy auction process for the CAM be eliminated. PG&E advocates for a net cost allocation methodology to determine the net capacity costs of specific contracts without the need for an energy auction, as used in other recent cases, for all CAM-eligible resources and the energy auction should be eliminated. SCE notes that it is the only IOU that has held energy auctions. In SCE's experience, energy auctions have served their intended purpose and the energy auction process has worked well. Therefore, SCE does not see a need to reform the CAM energy auctions at this time. SCE seeks to allow the utilities to make a request to refrain from conducting an energy auction when an energy auction is neither appropriate nor necessary.

SDG&E comments that, in previously considering application of the CAM to IOU procurement, the Commission permitted parties to establish a proxy calculation similar to the non-auction cost calculation mechanism adopted in D.07-09-044 in the JPP. SDG&E proposes that the JPP (or an administrative methodology based on the JPP) be deemed to be a fully-available alternative to the use of an energy auction to determine the net capacity costs for resources subject to the CAM. SDG&E recommends eliminating the restriction that the administrative methodology may be used only if an auction is unsuccessful or has not yet occurred.

WPTF believes the Commission should examine carefully how to value the energy component and the residual capacity costs, whether through an auction or otherwise. WPTF argues that by ascribing too little value to the energy component, the IOU is able to layer more net capacity costs on its competitive CCA and ESP suppliers, resulting in an unnecessary and unfair cost shifting to retail choice customers. WPTF emphasizes that it is important for the Commission to ensure that the full value of energy and other related products is netted from the contract price, as proposed by MEA, and AReM/DACC in the recent phase of this proceeding.

AReM/DACC's fundamental concern with the energy auction and the proxy calculation used when there is no auction is that they rely on the short-term value of energy to produce an imputed capacity value from a long-term contract price. D.07-09-044 requires that the back-to-back toll product available for the energy auction be limited to a term not to exceed five years. AReM/DACC believes that the Commission should consider modifying this restriction to allow the auction products of a longer duration, and should consider implementing a longer minimum term (currently at one year) to better reflect the incremental hedging value of the PPA. AReM/DACC also believes that JPP should be reexamined so that the full value of energy and other products is netted from the contract price.

Whether or not the Commission decides to reform the CAM energy auctions, MEA believes the Commission ought to ensure that CAM-eligible procurement is driven solely by reliability needs.

8.4.3 Discussion

In D.13-02-015, we considered potential changes to the CAM energy auction. At that time, we found: "The record does not provide an adequate and persuasive basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism." (D.13-02-015, Finding of Fact 53.) With the additional comment in this Track of the proceeding, we are now prepared to act on this issue. We will now eliminate any requirement that a utility undertake a CAM energy auction as a tool to net capacity costs for CAM facilities. However, a utility may *voluntarily* decide to conduct such an auction if it so prefers. This optional approach follows from the language of Section 365.1(c)(2)(C), which provides in relevant part that: "An energy auction shall not be required as a condition for applying this allocation, but may be allowed as a means to establish the energy and ancillary services value of the resource for purposes of determining the net costs of capacity to be recovered from customers pursuant to this paragraph . . "

For reasons of transparency and accuracy, parties' comments largely recommend removal of the CAM energy auction. While there may be benefits to such energy auctions (*e.g.*, the hedging benefits of longer term tolling agreements relative to the short term JPP), there are also benefits to having shorter term ways to net capacity costs if situations change.

We are concerned with protecting all ratepayers, and need to ensure that all ratepayer groups (including DA and CCA load) are treated equally. This is the reason that the CAM was developed in the first place – to ensure that all ratepayer groups were treated equally. We conclude that it would be unfair to create a system that allows one ratepayer group to allocate costs to other ratepayers when there is reason to believe that those costs are not sufficiently justified or that the costs are likely to mismatch actual market value.

While the JPP might arrive at costs that are not always indicators of real value, given the complexity of the CAISO markets, the mechanics of the JPP allow for a forecast and a true up later. On the other hand, the energy auctions arrive at the highest bid, regardless of future energy prices, and there are insufficient safeguards to ensure that the final award is accurate or that the auction itself is fair and robust. There are elements of the auction that may not present true equality between bidding parties. It is also unclear if the tolling agreements that result from the energy auctions abide by the CAISO tariff or allow for implementation of CAISO tariff the way a toll with the original purchaser would. For example, requirements for generators to submit economic bids to count for flexibility for can be problematic when the owner of the plant sells a tolling agreement, where the purchaser might not be the scheduling coordinator. The replacement requirement for RA resources that take planned maintenance may lead to compliance problems when the facility is not scheduled by the same party that owns the tolling agreement.

For these reasons, we remove the requirement for an energy auction as a tool to net capacity costs for CAM facilities, and instead allow all utilities to utilize the mechanism adopted in the JPP to set the residual capacity costs that would be allocated to benefitting customers unless the utility prefers to conduct an energy auction for a particular resource.

8.4.4 Question:

Should resources built in one IOU's service territory spread costs across all the California Public Utilities Commission's jurisdictional load-serving entities?

8.4.5 Parties Positions

PG&E recommends that the Commission should determine if the flexibility need being met by the resource is a system or local reliability need, and if the resource meets that reliability need in a manner that benefits all customers of the IOU being ordered to procure it. If so, PG&E recommends that the net capacity costs are to be allocated to the bundled, DA, and CCA customers in the distribution service territory of the IOU ordered to procure the resource, and not to the bundled, DA, and CCA of customers in the distribution service territory of other IOUs.

SCE recommends that, to the extent that a system need exists for new flexible generation resources, but it is preferable to site all the new resources in one IOU's service territory, the Commission should take action to ensure an equitable allocation of cost to all CPUC-jurisdictional customers by requiring each IOU to contract for new flexible generation resources on a load ratio share basis in the identified IOU's service territory. Alternatively, SCE suggests the Commission can authorize one IOU to contract for the required new flexible generation resources and allocate a load ratio share of the CAM costs to the other two IOUs for recovery from their system customers.

SDG&E considers it to be premature to address this issue at this time.

AReM/DACC recommends that, along with ensuring that the application of CAM takes into account whether an ESP or CCA is already meeting the reliability needs of their customers and therefore should be exempt from CAM, the Commission should consider would be to afford ESPs and CCAs the opportunity to self-fulfill their system or local reliability needs and avoid CAM charges based on IOU procurement.

CCSF does not support having bundled customers or CCA distribution customers of one IOU subject to CAM non-bypassable charges from procurement by another IOU. MEA believes the CAM should not reach beyond the footprint of a given IOU because small LSE's such as MEA would face a significant burden in monitoring procurement proceedings of all three IOUs in order to represent the interests of their customers.

8.4.6 Discussion

We agree with PG&E, CCSF, and MEA that the criteria to justify CAM procurement should be specific enough that the procurement can be focused on one IOU service area or another, and that it is unreasonable for one IOU's customers to subsidize the reliability improvements of another. A concern with applying the CAM in this context is that the customers paying for the CAM facility would see only incremental benefit from the facility, while another IOU's customers would not pay for the reliability improvements they enjoy.

While it is sometimes advisable to focus procurement in a certain place, we find it reasonable to require each IOU to manage the reliability of its own service area. We do not expect to require all IOUs to share the costs of incremental new facilities, but instead to authorize construction by each IOU for the load nearest them. It is not efficient or effective for a customer to receive Local RA credit for a facility in another service area, since the LSE serving that customer would not have the applicable Local RA obligation to offset. This proposition seems to violate principles of cost causation, and creates possibility of excess procurement.

9 Energy Resource Recovery Account (ERRA) compliance filing requirements

9.3 Question:

Should the Commission require more consistency among the QCR's for the three major electric IOUs? If so, what areas of the QCRs currently lack consistency?

9.3.1 Current Rule

The current format and timing of the QCR submission was set via Commission decision D.07-12-052. There was a template adopted there that specified the format of the reports and the content of the attachments.

9.3.2 Parties' Positions

PG&E does not see a need to make changes to the QCR at this time. SCE and SDG&E claim there is a high degree of consistency currently exists among IOUs' QCRs.

ORA recommends that the Commission should develop a more consistent and standardized reporting template for the QCRs filed by the IOUs. One particular area where ORA believes the QCRs lack consistency is in the reporting format for newly signed electricity contracts.

CEJA urges the Commission to require consistency in the format for energy resource recovery account compliance reports among the three major

IOUs to allow interested members of the public and regulators to easily review the information presented.

9.4 Question:

Are any changes to information filed in QCRs necessary to ensure that IOU procurement is compliant with Commission rules?

9.4.1 Current Rule

The current QCR format was adopted by D.07-12-052. The format has grown large, with utilities filing multiple attachments with a large amount of information. There is also a standing monthly data request that the utilities have been submitting since its issuance in 2004. To some extent these two data submissions are duplicative. In addition there are numerous data requests that Energy Division staff submits to the utilities for various elements of their procurement data.

9.4.2 Parties' Positions

PG&E, SCE and SDG&E agree that there is no inconsistency among the IOUs in the information presented in the QCRs.

MEA finds the current QCRs to be largely useless to the public due to assertions of confidentiality over the most relevant procurement information. Consistent with MEA's earlier comments regarding the need for greater IOU procurement transparency, the IOUs should include more substantive information in the public versions of the QCRs. CEJA recommends that the Commission require that the quarterly compliance reports include information on the three major electric IOUs' loading order compliance.

9.5 Question:

Should the QCR evaluation process be moved from a quarterly evaluation to an annual, semiannual (or other term) process?

9.5.1 Current Rule

The current rule places the QCR submission on quarterly basis.

9.5.2 Parties' Positions

PG&E, SCE and SDG&E all maintain that the QCR evaluation process should remain a quarterly evaluation. PG&E contends the quarterly cycle is the optimum in terms of ensuring the IOUs' transactions are expeditiously reviewed against the IOUs' Commission-approved procurement plan's upfront standards, consistent with Public Utilities Code Section 454.5(c)(3).

CEJA urges the Commission to continue requiring the quarterly compliance reports every quarter.

ORA recommends the following: 1) The Commission should require each IOU to submit a Contract Amendment Compliance Report prepared by an authorized Independent Evaluator as an appendix to the IOU's Energy Resource Recovery Account Annual Compliance Application; and 2)The Commission should require an independent process evaluation of each IOU's Least-Cost Dispatch methods, procedures, documentation, software models, and model assumptions once per two years.

9.6 Discussion of Questions 9.1, 9.2 and 9.3 (ERRA filing requirements)

It is necessary to balance the need for greater information access with the difficulty in producing that information and in evaluating it. Commission staff (as well as stakeholders or PRG members) must be able to use the information submitted in a useful way. Even if the Commission aggregates and publishes reports for the public in the interests of managing transparency, the information must at first be clear and usable. In addition to PRG members who have a use for procurement information related to procurement oversight, the CAISO has a use for mid to long term procurement information to inform CAISO decisions about backstop procurement or forecasts of potential resource retirement.

In our evaluation of the QCR format, we find that there is sufficient consistency as to format, but there may be needs for added consistency as to purpose and meaning. We find that the QCR submissions are sufficiently standardized as ordered by Commission decision. However, the information presented is complicated and voluminous. Information presented in the QCRs is often also available from other sources, so it is unclear what the best way to get the data and minimize reporting is. Currently it is unclear as to how to best effectuate the purpose of the QCR submissions (procurement oversight and assurance that the utilities are following their procurement rules) so several areas of the QCR reports could be redundant or unnecessary. A reevaluation of the purpose and content would aid Commission staff in making best use of the QCR data. This reevaluation is likely to reveal that needs have changed since the QCR format was last amended in 2008; for example, some information may be needed once per year, and some information needed quarterly. We will seek to standardize how the Commission receives and stores utility procurement data.

At this time, no changes to content or timing are adopted. We will require Energy Division to begin investigating opportunities to understand and potentially reduce the QCR reporting to just the most useful elements, to eliminate redundant reporting, and to create guidelines that enable consistency across the utility QCR submissions.

We adopt a process for QCR revisions. The process should occur within the next 90 days, be cooperative, and create a QCR guide similar to the guide for RA reporting. We require the utilities to devote a portion of an upcoming PRG meeting to this task, by discussing the information they currently submit in the QCRs with PRG members, describing why the data is submitted (particularly data that is also available online or data that is submitted pursuant to other data requests) and to ensure that PRG members have had a chance to comment on the content and format of the QCRs for their purposes as PRG members.

There are a variety of purposes for QCR information, including the auditing functions of ensuring that the procurement rules are met. Energy Division staff will lead a dialogue to ensure that all users of the QCR data are able to continue achieving their goals with whatever new guidelines are promulgated.

10 Refinements to the Independent Evaluator (IE) program

10.1 Question:

Please comment on the following proposal:

i. The rules for whom or which entity may qualify to be in the IE pool remain the same;

ii. The IOUs may not limit the IE's interactions with the Commission, specifically in terms of nondisclosure agreements that restrict information sharing;

iii. IEs are positioned on particular assignments through a random selection process, removing IOU influence over which IE may be assigned; and

iv. IEs may remain in the selection pool for 10 years (rather than up to 6 years), subject to evaluation every 3 years (maintain current requirement for reassessment).

10.2 Parties Comments

PG&E endorses keeping the current rules for IE qualification in place. PG&E supports having an IE remain in the selection pool for ten years and subject to evaluation every three years. SCE agrees that the rules pursuant to D.04-12-048 and D.07-12-052 for whom or which entity may qualify to be in the IE pool should remain the same. SCE is not aware of any specific IOU behavior that has sought to limit an IE's interactions with the Commission. SCE believes that, consistent with the guidance provided in D.04-12-048, the IE selection process should be based on the skills offered by the IE, not a randomized process that would preclude the ability to match an IE's experience and knowledge to a particular solicitation process and energy products. SCE supports a proposal for IEs to remain in the selection pool for ten years, subject to evaluation every three years.

SDG&E does not recommend modifying the requirements for IE qualifications or assignments. SDG&E states that its nondisclosure agreement does not restrict IE interactions with the Commission; SDG&E claims that it does not attempt in any way to restrict information-sharing between the IE and the Commission.

WPTF considers the proposal cited as an improvement over the existing rules. WPTF recommends having the Commission's Energy Division, rather than the utilities, oversee the hiring and oversight of IEs in this LTPP.

Sierra Club recommends that, rather than perpetuating a system that has structural conflicts of interest built in the system, the Commission require its staff auditors to evaluate IOU procurement. CEJA requests that the rules for qualifying for the IE pool be modified to include qualifications to review other types of resources and environmental considerations including environmental justice.

IEP supports this proposal.

ORA agrees that the IOUs should not limit the IE's interactions with the Commission, specifically in terms of nondisclosure agreements which may restrict information sharing with the Commission. ORA opposes a random selection process of IEs on particular assignments because it may not select the best-fit IE, all factors taken into consideration, for a specific project. ORA does not oppose SCE's proposal to allow IEs to remain in the selection pool for up to three years, but opposes allowing IEs to remain in the selection pool for 10 years on the basis that this would impede other potential IE candidates from competing for an IE role.

CEJA supports parts (ii) and (iii) because these proposals may reduce potential conflicts and allow for an independent evaluation. CEJA does not support part (iv) because of the potential for conflicts that arise after participating in the process for a number of years.

10.2.1 Discussion

We agree with PG&E that it is not necessary to change the rules for whom or which entity may qualify to be in the IE pool. The current rules pursuant to D.04-12-048 and D.07-12-052 ensure that experienced and well-qualified candidates are selected for the pool.

There is no evidence that IOUs have limited the IE's interaction with the Commission in terms of nondisclosure agreements that restrict information sharing. New rules facilitating IE interaction with the Commission are not necessary.

Currently, IEs are assigned projects by matching their expertise and experience with the needs of a project. We agree with SCE and ORA that it is beneficial to match the IE's expertise and skills with details of a particular assignment. Using a random selection process for IE assignment does not provide such benefit. Therefore, the Commission will retain the current process for IE assignment.

Existing rules allow IEs to remain in the selection pool indefinitely while subject to re-evaluation every two years, pursuant to D.07-12-052. We do not find a need to limit the terms of IEs in the pool. We agree with PG&E and SCE that IEs can be re-evaluated every three years instead of two years to provide more opportunity for IEs to demonstrate their performance. Therefore, the Commission will continue to allow IEs to remain in the selection pool without term limits, subject to evaluation every three years instead of every two years.

11 Comments on Proposed Decision

The proposed decision the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ____________________, and reply comments were filed on ____________________ by ____________________.

12 Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and David M. Gamson is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. IOU procurement of authorized energy, natural gas, emissions and financial hedging products is restricted by predetermined volume limits and transaction rate limits approved in the bundled procurement plan, based on a forecast of future procurement needs. In effect, the bundled procurement plan provides an upper limit on procurement.

2. Procurement levels for fossil-fuel resources or preferred resources are addressed through Commission policies in various proceedings (including other phases of this one) which seek to implement statutes, policies and goals in these areas.

3. While there are potential benefits of mandating minimum procurement limits, it is not possible at this time to ensure that bundled customers would not bear a disproportionate share of reliability costs.

4. Minimum procurement levels are already established in the RA proceeding. Additional minimum procurement requirements for any particular electric product or service could increase ratepayer costs.

5. IOUs are expected to plan for reasonable amounts of departing load and then only procure for the assumed amounts of retained bundled load. IOUs appear to take into account their expectations for departing load in their procurement forecasts.

6. There may be a difference between the IOU's calculation of departing load and other objective measures of departing load, thus necessitating clarification of rules.

7. The current rules governing confidential treatment of IOU data are set forth in D.06-06-066.

8. The Commission has not to date allowed public disclosure of RFO bid and offer information, as such disclosure could reasonably be expected to affect the market to the detriment of IOUs and their ratepayers. Nothing has changed in this regard.

9. Allowing for the incremental capacity of existing plants or repowered plants to participate in long-term RFOs may alleviate some need to build additional capacity. Allowing for such capacity to participate in long-term RFOs may enhance the operation of the plant and increase its value to the system.

10. There are no current restrictions on contract lengths for new facilities.

11. There is a gap in Commission policies regarding review of medium term bilateral procurement contracts of three consecutive months or greater and under

five years in duration (with the exception that power purchase agreements with OTC plants with contract duration of greater than two years must be submitted to the Commission's via a Tier III advice letter).

12. While there are benefits to CAM energy auctions, such as the hedging benefits of longer term tolling agreements, there are also benefits to having shorter term ways to net capacity costs if situations change.

13. The CAM was developed to ensure that all ratepayer groups were treated equally.

14. The energy auctions arrive at the highest bid, regardless of future energy prices, and there are insufficient safeguards (such as a forecast and a true up) to ensure that the final award is accurate or that the auction itself is fair and robust.

15. There are dynamics to the energy auction that may not present true equality between bidding parties.

16. Applying the CAM process to resources located in another IOU's service area could result in customers who pay for the CAM facility seeing little or no benefit from the facility, while another IOU's customers do not pay for the reliability improvements they enjoy.

17. It is not efficient or effective for a customer to receive Local RA credit for a facility in another service area, since the LSE serving that customer would not have the applicable Local RA obligation to offset.

18. Utilities currently have no authorization to construct facilities outside their service area for reliability purposes, and demand response programs focus on customers that the utilities bill directly.

19. Quarterly compliance report submissions are sufficiently standardized but the information presented is complicated and voluminous.

20. A reevaluation of the purpose and content of quarterly compliance reports would aid Commission staff in making best use of the data in these reports.

21. The current rules pursuant to D.04-12-048 and D.07-12-052 ensure that experienced and well-qualified candidates are selected for the IE pool. However, evaluation of IEs every two years provides limited opportunity for IEs to demonstrate their performance.

22. There is no evidence that IOUs have limited the IE's interaction with the Commission in terms of nondisclosure agreements that restrict information sharing.

Conclusions of Law

1. It is not necessary to establish new minimum or maximum procurement levels for bundled procurement plans at this time, as there is no corresponding or overriding benefit to further minimum procurement requirements.

2. The Public Utility Code Section 454.5(b)(9) requirement of "a showing that the procurement plan will fulfill its unmet resource needs from eligible renewable energy resources in an amount sufficient to meet its procurement requirements pursuant to the California Renewables Portfolio Standard Program" and that each utility "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible" is ongoing.

3. Issues regarding centralized capacity markets are not within the scope of this proceeding. Similarly, multi-year forward contracting requirements should not be considered in this proceeding. Issues regarding limits on flexible capacity are encompassed in the RA proceeding.

4. It is necessary to clarify requirements from D.12-01-033 regarding calculations of departing load in utility procurement forecasts.

5. It is not in the public interest to provide public disclosure of RFO bid and offer information at this time.

6. It is in the public interest to promote greater reporting of the information that the Commission regularly collects from the utilities regarding procurement activities, either as aggregate or in specific, to the market and the CAISO, to the extent that confidentiality is not compromised.

7. In order to allow incremental capacity to bid into a new generation RFO, the term "incremental capacity" should be defined as: "capacity incremental to what was assumed in the underlying needs assessment." In this context, the following terms should also be defined:

- Upgraded plants: Upgrades are defined as expanding the generation capacity at, or enhancing the operation of, a generation facility, so long as such incremental megawatts can provide the necessary attributes that the Commission has authorized the utility to procure. An upgraded plant or a plant with incremental capacity additions would be a plant where the main generating equipment is retained and continues to operate.
- Repowered plants: Repowers are defined as capital investments that extend the useful life of a generation facility, after the planned retirement date. A repowered facility is a facility where the main generating equipment (such as the turbine) is changed out for new equipment.

8. It is in the public interest to impose greater oversight of medium term bilateral contracts. Utilities will now be required to submit Tier II Advice Letters seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 MW. This rule is in addition to all previous procurement rules.

9. It would be unfair to create a CAM system that allows one ratepayer group to allocate costs to other ratepayers when there is reason to believe that those costs are not sufficiently justified.

10. Energy auctions should no longer be required to net capacity costs for CAM facilities. Instead all utilities should use the mechanism adopted in the JPP to set the residual capacity costs that would be allocated to benefitting customers.

11. Except as currently provided for in the CHP settlement, it is unreasonable to use the CAM process so that one IOU's customers subsidize the reliability improvements of another; it is reasonable to require each IOU to manage the reliability of its own service area.

12. At this time, no changes to content or timing of quarterly compliance reports should be adopted, pending Energy Division review of opportunities to reduce such reporting to the most useful elements, to eliminate redundant reporting, and to create guidelines that enable consistency across the utility submissions.

13. There is no need to change the IE rules regarding: a) which entity may qualify to be in the IE pool; b) IE interaction with the Commission; and c) the current process for IE assignment.

14. It is reasonable to allow IEs to be re-evaluated every three years instead of two years to provide more opportunity for IEs to demonstrate their performance.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the IOUs) shall estimate

reasonable levels of expected Direct Access and Community Choice Aggregation departing load over the 10-year term of the IOUs bundled plans, using information provided by the California Energy Commission and/or by a Community Choice Aggregator in its Binding Notice of Intent. The IOUs shall then exclude this departing load from their future bundled procurement plans, and only procure for the assumed amounts of retained bundled load. Having been excluded from the bundled portfolio planning scenarios, the forecasted Direct Access and Community Choice Aggregation departing load shall not be subject to non-bypassable charges for any incremental stranded procurement costs incurred by the IOUs for the period after the date of departure assumed in their approved bundled plans.

2. In order to allow incremental capacity to bid into a new generation Request for Offers, the term "incremental capacity" is defined as: "capacity incremental to what was assumed in the underlying needs assessment." In this context, the following terms are also defined:

   1. Upgraded plants: Upgrades are defined as expanding the generation capacity at, or enhancing the operation of, a generation facility, so long as such incremental megawatts can provide the necessary attributes that the Commission has authorized the utility to procure. An upgraded plant or a plant with incremental capacity additions would be a plant where the main generating equipment is retained and continues to operate.
   2. Repowered plants: Repowers are defined as capital investments that extend the useful life of a generation facility, after the planned retirement date. A repowered facility is a facility where the main generating equipment (such as the turbine) is changed out for new equipment.

3. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall submit Tier II Advice Letters

seeking Commission approval to enter into a medium-term bilateral contract if the size of the contract is over 50 megawatts. This rule is in addition to all previous procurement rules.

4. Energy auctions shall no longer be required to net capacity costs for facilities subject to the Cost Allocation Mechanism. Instead Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall use the mechanism adopted in Decision 07-09-044, known as the "Joint Parties' Proposal," to set the residual capacity costs that would be allocated to benefitting customers.

5. No later than ninety (90) days after the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company devote a portion of an upcoming Procurement Review Group meeting to creation of a quarterly compliance reporting guide similar to the guide for Resource Adequacy reporting.

6. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall re-evaluate Independent Evaluators every three years.

7. The September 20, 2012 Motion of Pacific Gas and Electric Company to move Track 3 multi-year procurement issues to the Resource Adequacy proceeding (Rulemaking 11-10-023 or its successor), and other matters, is denied.

8. Rulemaking 12-03-014 shall remain open.

This order is effective today.

Dated ____________________________, at San Francisco, California.

Briefing on NUCLEAR ISSUES
(by ED staff)

Nuclear Power Plants: Size and Ownership

- PG&E owns Diablo Canyon Power Plant (DCPP Units 1 and 2 located near San Luis Obispo and Humboldt Bay Power Plant (HBPP) Unit 3 near Eureka CA.

    1. DCPP 1 and 2 are operating plants generating approx 1100 MW each.
    2. HBPP 3, a 63-MW boiling water reactor is currently being decommissioned.

- SCE owns 78.21% of San Onofre Nuclear Generating Station (SONGS) located adjacent to Camp Pendleton near San Clemente CA.

    1. SONGS 2 and 3 rated at 1120 MW each; currently permanently shutdown due to steam generator problems and slated for decommissioning to begin mid-2015.
    2. SONGS 1 is being decommissioned since 1999.

- SDG&E owns 20% and the City of Riverside owns 1.79% of SONGS 1, 2, and 3.

- SCE owns 16.5% of Palo Verde Nuclear Generating Station. This three-unit nuclear plant is located near Phoenix Arizona.

- Operating license termination dates: DCPP 1 2024; DCPP 2 2025; SONGS 2 & 3 2022; Palo Verde 1 2044; Palo Verde 2 2046; Palo Verde 3 2047. In April 2011, the NRC granted 20-year license extension to Palo Verde.

- The Nuclear Regulatory Commission (NRC) has jurisdiction over the licensing, safety, and operational aspects of nuclear power plants. The CPUC has jurisdiction primarily related to cost issues.

<u>Steam Generator Replacement at SONGS</u>

- In 2005 D.05-12-040, the CPUC authorized total spending of $680 million (2004 dollars) for the steam generator replacement project (SGRP) for SONGS 2 and 3 including removal of the original 2 SGS in each unit and disposal. D.11-05-035 reduced the amount to $671 million.

- As of June 30, 2012, SCE's investment in the SGRP is $593 million, and SDG&E's investment is $178 million.

  1. The CPUC will review the reasonableness of the actual SGRP expenditures including disposal upon submission of SCE's final costs for the project.

  2. That submission originally planned for late 2012 is now expected March 15, 2013 and be incorporated into Phase 3 of the SONGS OII.

  3. D.05-12-040 authorized recovery of revenue requirements associated with the SGRP in rates after each unit went back into operation.

- SONGS 2 steam generator replacement was completed on April 11, 2010, and revenue requirements associated with the Unit 2 SGRP were recorded in balancing accounts at that time. SCE included $97 million and SDG&E included $18 million in 2011 rates. SCE included $60 million and SDG&E $18 million in 2012 rates associated with the SGRP for SONGS 2.

- The Unit 3 SGRP was completed on Feb 18, 2011, and revenue requirements associated with Unit 3 were recorded in balancing accounts at that time.

  1. SCE included $101 million in 2012 rates associated with the replacement of the Unit 3 SGs.

  2. SDG&E included $14 million in 2012 rates associated with the replacement of the SGS for SONGS 3.

  3. Thus, the total recovery included by SCE in 2011 and 2012 for SG replacement is $258 million and the total included by SDG&E is $50 million. The total for both utilities for the SGRP already in rates so far is $308 million.

- On March 8, 2013, the NRC released to the public the non-proprietary version of the MHI root cause analysis report it prepared in 2012.

- SCE submitted its application A.13-03-005 on March 15, 2013 for the actual costs of the SONGS steam generator replacement project (SGRP) including removal and disposal of the four old steam generators. SCE indicated it spent $768.5 million in nominal dollars for the SGRP. SDG&E also submitted an application A.13-03-014 for its share of the SGRP costs, above. The costs associated with the SGRP will be addressed in Phase 3 of the SONGS OII beginning 2014.

- On May 4, 2013, the ASLB ruled that SONGS 2 cannot restart until the NRC holds a formal license amendment proceeding with full public participation.

- On June 7, 2013, SCE notified the NRC that it will permanently shutdown SONGS Units 2 and 3.

- On July 18, 2013, SCE submitted a Notice of Dispute to Mitsubishi seeking recovery of costs for the replacement steam generators that lead to the shutdown of SONGS 2 and 3.

- On Sept. 20, 2013, the NRC issued an inspection report preliminarily indicating potential violations related to the SONGS steam generators. A white finding of low to moderate safety significance against Unit 3 for inadequate design of the SGs and a green non-cited violation for Unit 2 because the tubes did not actually leak. The NRC also issued a Notice of Non-Conformance to Mitsubishi.

- On Oct.21, 2013, SCE replied to the NRC that it agreed with the NRC's inspection findings and level of violation.

SONGS OII I.12-10-013:

- OII I.12-10-013 initiated because SONGS 2 and 3 have been non-operational since January 2012 due to steam generator issues.
- SONGS 3 fuel removed from reactor and placed in wet fuel storage pool. SONGS 3 is not expected to restart with the existing defective steam generators.
- In Oct 2012, SCE applied to the NRC to restart and operate SONGS 2 at 70% power. This application is still under review by NRC. The NRC has issued 67 Requests for Additional Information. NRC expected to issue a decision in June 2013.
- Assigned ALJ Melanie Darling and Commissioner Florio.
- Prehearing conference held on Jan 8, 2013.
- Public Participation Hearing Feb 21 in Costa Mesa. An additional PPH is scheduled for Oct. 1, 2013 in San Diego.
- Initial testimony filed by SCE and SDG&E Dec 17, 2012.
- Additional testimony filed Jan 9, 2013.
- Scoping memo for Phase 1 issued Jan 28, 2012. Allows for collaboration with CA Energy Commission.
- SONGS OII will have 3 or 4 phases. Each phase will have its own PHC and scoping memo.

1. Phase 1 – Scope includes the nature and effects of the steam generator failures in order to assess the reasonableness of SCE's consequential actions including removal of fuel from unit 3; reasonableness of SONGS-related expenditures incurred in 2012 including replacement power; reasonableness of expenditures for community outreach and emergency preparedness related to the SONGS outage; and if any rates preliminarily approved in the 2012 GRC should be refunded SCE and SDG&E established SONGS Outage Memorandum Accounts to record 2012 expenditures incurred since Jan 1, 2012 per the OII. Phase 1 expected to be concluded by Fall 2013.
2. Phase 2 – Envisioned to address issues related to any reductions to SCE's rate base. Phase 2 expected to be concluded by the end of 2013 with a decision by Feb 2014.

3. Phase 3 - Envisioned to address the causes of the steam generator damage, allocation of responsibility, reasonableness of the steam generator replacement costs and possibly how any liability issues between SCE and Mitsubishi are resolved. SCE filed in March 2013 the actual costs incurred for the steam generator replacement and disposal of the old SGs. Approximately $260 million is already in rates, but subject to reasonableness review and refund. Phase 3 expected to begin in early 2014.
4. Phase 4 – This phase might be needed to address adjustments to SCE's 2013 revenue requirement to reflect lower than forecast O&M expenses, capital spending, replacement power, and other SONGS expenses.

- Phase 1 Scoping memo issued Jan 28, 2013. Allows for collaboration with CA Energy Commission.
- ED to provide staff support for Demand Response, Replacement Procurement, Energy Efficiency issues in Phase 1.
- Phase 1 testimony filed by parties on Mar.29, 2013.
- Hearings for Phase 1 held May 13 – 17, 2013.
- Additional Phase 1 hearings on additional testimony on replacement power held Aug. 5-6, 2013.
- Phase 2 Pre-hearing conference held July 12, 2013.
- PPH held on Oct. 1, 2013 in San Diego.
- Phase 2 hearings held Oct. 7 – 11, 2013.
- The PD for Phase 1 is was mailed on Nov. 19, 2013 to be on the Dec 19, 2013 Commission agenda.
- A two-year contract was approved for Dr. Robert Budnitz to be an expert consultant to Energy Division on technical issues primarily the steam generator issues of Phase 3 of the SONGS OII.
- Phase 3 of the SONGS OII expected to begin in Feb. 2014.

Decommissioning

- In accordance with NRC regulations, all nuclear plant owners are required to maintain trust funds to ensure sufficient amounts will be available to decommission their nuclear plants.
- PG&E maintains trust funds for DCPP 1 and 2 and HBPP 3. The trust fund balances as of June 2013 are HBPP 3 - $222 million; DCPP 1 - $925 million; DCPP 2 - $!,288 million
- SCE maintains trust funds for SONGS 1, 2, and 3. The trust fund balances as of June 2013 are SONGS 1 - $206 million; SONGS 2 - $1,287 million; SONGS 3 - $1,451 million
- SDG&E maintains trust funds for its 20% ownership of the SONGS. The trust fund balances as of June 2013 are SONGS 1 - $100 million; SONGS 2 - $347 million; SONGS 3 - $401 million.
- SCE maintains trust funds for its 16.5% ownership of Palo Verde.
- Forecasts of expected decommissioning costs are reviewed every three years at the CPUC during the Nuclear Decommissioning Cost Triennial Proceeding (NDCTP).
- On Dec 21, 2012, PG&E, SCE, and SDG&E filed applications in the 2012 NDCTP A.12-12.-012 with updated decommissioning plans and costs.
- A.12-12-012 assigned to ALJ Darling and Commissioner Ferron.
- PHC for A.12-12-012 set for March 27, 2013.
- In accordance with D.13-01-039 from Phase 2 of the 2009 NDCTP, PG&E can submit Tier 2 advice letters for authorization to disburse funds from the trusts for decommissioning activities for HBPP 3 in accordance with the decommissioning plans. Decommissioning of HBPP 3 is about 50% complete.
- D.13-01-039 allows for increase in investments in stocks and lower rated – higher yield domestic and foreign bonds to increase the overall yield of the trust funds.
- In accordance with a 1999 decision, SCE can disburse funds from its trust for decommissioning SONGS 1 without prior notification to the CPUC as long as the

disbursements are within the forecasted amounts approved in the latest NDCTP. Decommissioning of SONGS 1 is about 90% complete.

- By end of 2013, HBPP decommissioning will have approved disbursements of $550 million. Total authorized thru 2020 is $589 million. There remains about $40 million in planned expenditures, based on 2009 decommissioning costs.
- Nuclear decommissioning, storage, and security costs are rising sharply. In the 2012 NDCTP –
    1. PG&E requests additional $500 million for HBPP not included in any previous NDCTP for removal of concrete caisson around reactor vessel 80 feet below grade.
    2. PG&E requests $551 million for DCPP for wet fuel storage and security.
    3. PG&E and SCE assume spent fuel needs to be retained in wet pool for 12 years before transfer to dry cask storage. A shorter period 5 – 8 years would reduce decommissioning costs.
    4. SONGS decommissioning costs estimated at $4.132 billion. This is an increase of $39 million from 2009 NDCTP.
    5. SCE's share of Palo Verde decommissioning cost is $513 million
- March 27, 2013 Pre-hearing conference held.
- A.12-12-012 for PG&E and A.12-12-013 for SCE and SDG&E were consolidated.
- Hearings held Aug. 7-9, 2013 for HBPP Unit 3.This bifurcation is being considered as Phase 1 of the 2012 NDCTP. A separate decision for HBPP 3 is expected by the end of 2013.
- Hearings held Oct. 21-25, 2013 for DCPP, SONGS, and Palo Verde. This will be considered Phase 2 of the 2012 NDCTP with a decision in early 2014.
- SCE submitted testimony on July 22, 2013 for premature shutdown of SONGS 2 and 3, with decommissioning beginning mid-2015.
- Proceeding needs to consider concern over refunds from Dept of Energy for not accepting spent nuclear fuel. HBPP puts credit (about ($135 million) to decom costs in this proceeding. DCPP puts credit (about $150 million) in its GRC. SONGS puts credit ($142 million) in ERRA.
- SCE is expected to submit a detailed site-specific decommissioning plan for SONGS 2 and 3 in 2014, which will be reviewed in the 2015 NDCTP.
- SCE to submit a Post Shutdown Decommissioning Activities Report (PSDAR) to the NRC by June 2015.

<u>Enhanced Seismic Studies and Independent Peer Review Panel (IPRP) for DCPP Independent Peer Review Group (IPRG) for SONGS</u>

- Initially interest in enhanced seismic studies arose because of intent by PG&E and SCE to request from NRC operating license extensions for 20 additional years for DCPP and SONGS.
- CA Energy Commission AB-1632 Report recommended the utilities to perform enhanced seismic studies with 2-D and 3-D seismic surveys in the areas on-shore and off-shore DCPP and SONGS.
- Assigned ALJ Robert Barnett and Commissioner Florio.
- DCPP IPRP established by D.10-08-003.

- SONGS IPRG established by D.12-05-004.
- The CPUC authorized approximately $64 million each for enhanced seismic surveys at DCPP (D.12-09-008) and SONGS (D.12-05-004).
- IPRP / IPRG members consist of technical experts from CEC, Coastal Commission, CA Seismic Safety Commission, CA Emergency Management Agency, CA Geological Survey, CPUC.
- County of San Luis Obispo also represented in IPRP for DCPP seismic studies.
- IPRP and IPRG review 2-D and 3-D seismic studies proposed by PG&E and SCE for on-shore and off-shore areas in vicinity of DCPP and SONGS.
- The CCC denied permit for PG&E to conduct any 3-D surveys off-shore DCPP in 2012, as well as rejected SCE's application for SONGS off-shore seismic studies over concerns related to disruption to marine life during the high energy testing needed to perform 3-D surveys..
- PG&E's application for DCPP license extension at NRC is currently on hold. PG&E filed an application at the CPUC requesting $80 million to cover costs related to re-licensing activities. This application was suspended.
- The latest IPRP / IPRG meetings were held on July 11, 2013.
- IPRP Report No.5 with comments and discussion on Hosgri fault issued Mar. 25, 2013.
- On Mar. 29, 2013 the IPRP held an information meeting with PG&E to review Pt Buchon 2D/3D seismic survey data.
- PG&E's data of the faults around Pt Buchon indicate that the Shoreline Fault is segmented. One of the branches has been named Pt Buchon Fault. While it might be a northern extension of the Shoreline Fault, PG&E is considering it for now as a separately named fault.
- The IPRP meeting with PG&E on June 6 to discuss IPRP draft Report No.6 on seismic ground motion hazards analysis.
- IPRG Report No. 2 issued July 17, 2017 recommending continuation of seismic projects for SONGS.
- IPRP Report No. 6 regarding DCPP site characterization analysis issued August 12, 2013.
- SCE submitted AL 2930-E, which was approved effective Sept 13, 2013,to continue the seismic projects for SONGS except for installations of ocean bottom seismometers and the seabed floor sampling.
- Contracts for continued funding for the IPRP were extended through June 30, 2015.

Diablo Canyon Independent Safety Committee

- The DCISC is charged with reviewing and making recommendations concerning the safety of operations at DCPP.
- The DCISC consists of three members, one each nominated by the Governor, Attorney General, and Chair of CA Energy Commission for a three-year term.
- The position appointed by the Attorney General currently held by Robert Budnitz expires June 30, 2013. He already served two terms on the DCISC.
- Dr. Budnitz expressed interest in being re-nominated and serving a third term. There is also one other candidate who expressed interest.
- Announcement of an opening for this position is posted on the CPUC website. The new appointment would be for the term July 1, 2013 through June 30, 2016.

STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
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November 19, 2013

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Ratesetting

TO PARTIES OF RECORD IN INVESTIGATION 12-10-013

This is the proposed decision of Administrative Law Judges (ALJ) Melanie M. Darling and Kevin Dudney. This item is targeted to appear on Agenda No. 3328 for the Commission's December 19, 2013 Business Meeting, but may appear on a later agenda. Interested persons may monitor the Business Meeting agendas, which are posted on the Commission's website 10 days before each Business Meeting, for notice of when this item may be heard. The Commission may act on the item at that time, or it may hold an item to a later agenda.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:jt2

Attachment

Decision **PROPOSED DECISION OF ALJs DARLING and DUDNEY**
(Mailed 11/19/2013)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Southern California Edison Company and San Diego Gas and Electric Company Associated with the San Onofre Nuclear Generating Station Units 2 and 3.	Investigation 12-10-013 (Filed October 25, 2012)
And Related Matters.	Application 13-01-016 Application 13-03-005 Application 13-03-013 Application 13-03-014

DECISION ON PHASE 1 REGARDING 2012 SONGS-RELATED EXPENSES AND EXPENDITURES

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PROPOSED DECISION ON PHASE 1 RELATED TO 2012 SONGS-RELATED EXPENSES AND EXPENDITURES

1. Summary

This decision adopts interim rate reductions for Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) ratepayers as a result of reduced operating costs in 2012 following cessation of generation at San Onofre Nuclear Generating Station (SONGS). The decision orders refunds of approximately $94.0 million for overcollection of these costs.

The Commission has undertaken a multi-phase investigation into the actions and expenses by SCE and SDG&E (collectively Utilities) after a small radiation leak in a new steam generator led to discovery of serious vibration wear that forced both SONGS reactor units offline after January 31, 2012. This decision covers the first two phases which assess the reasonableness of 2012 expenses charged to ratepayers, including those incurred as a result of the outages.

Due to the non-operation of both units during 2012, the Commission declined to give final approval to the Utilities' estimated SONGS-related 2012 expenses in their respective general rate cases. Instead, the Commission deferred final review of that portion of revenue requirement to this investigation. Meanwhile, the Utilities have already collected a range of 2012 costs in rates. The Commission's Order Instituting Investigation ordered SCE and SDG&E to record all SONGS-related expenses, including those recovered in rates and report the expenses to the Commission on a regular basis.

In the 2012 GRC decisions, the Commission preliminarily allowed rate recovery of estimated SONGS Operations and Maintenance (O&M) and capital spending, subject to refund upon later review of recorded costs within the

framework of the reasonableness of SCE's actions (as operator) as events unfolded in 2012. The Phase 1 portion of the decision provides the deferred reasonableness review of 2012 GRC expenses, and other expenses incurred in 2012 as a result of the outages.

The Commission finds that, $273.9 million (2012$, 100% share[1]) in total 2012 Base Operations and Maintenance (O&M) and associated costs, were reasonable and necessary under the circumstances. This is $115 million less than the GRC-authorized amount of $389 million. In addition, we find that $45.1 million in O&M related to the refueling outage of Unit 2 was reasonable because the work was essentially complete before SCE knew the potential for serious damage in Unit 2.

Our review of capital spending determined that $134.1 million of $167.6 million in costs recorded by SCE was reasonable SONGS-related capital spending to safely maintain the plant. Based on excess capital additions, the Commission orders a 20% reduction of net 2012 additions to rate base and corresponding decreases to recovered capital costs. The overall result is the first SONGS-related refund to ratepayers in this investigation.

For SONGS, 2012 was a transitional year. SCE took reasonable steps to investigate the steam generator problems, and to mitigate some costs, as confirmed by the U.S. Nuclear Regulatory Commission. However, we find SCE to be single-minded about its restart plan, and slow to understand the technical challenges and regulatory timeframe required to implement it. SCE's decision to apply resources to a restart plan was the result of an unsound decision-making

[1] Most SONGS-related costs are reported as total costs, or 100% of the costs. "SCE share" means $78.21% of the total costs; SDG&E share means 20% of the total costs.

process, primarily because SCE did not consider cost effectiveness or alternatives such as putting Unit 2 into preservation mode, or realistically assess the regulatory hurdles blocking a reasonably foreseeable restart. Therefore, the decision adopts interim rate reductions based on removing an approximation of resulting costs.

The Commission orders the immediate refund of the excess rates collected in anticipation of normal operations at SONGS in 2012, which are deemed not just and reasonable given the fact that no generation occurred after January 31, 2012, nor was it likely to occur in 2012. This decision provides interim rate relief to ratepayers, but $122.6 million in other O&M costs related to the steam generators are still subject to final review in Phase 3. The Commission has not yet determined how much of these costs, if reasonable, will be charged to ratepayers because SCE has made insurance and warranty claims for some of the costs, and allegations of SCE fault remain to be examined.

To reach this decision, we reviewed recorded 2012 expenses in light of the nature and effects of the damage and SCE's consequential actions and costs. The decision establishes May 7, 2012 as the date by which SCE knew, or should have known, that the new type of tube wear linked to the tube leak in Unit 3 was also present, to a lesser degree, in Unit 2. Therefore, Unit 2 and Unit 3 would not likely return to normal operations in the short-term. Despite unduly optimistic reports to SCE's Board of Directors, SCE was aware that no submission to the NRC could occur for months, and SCE's internal actions signaled an understanding that repair options were far from developed. Therefore, reductions were primarily based on removal of an approximate SGIR-related revenue requirement, tempered by SCE's regulatory requirements to maintain the plant in a safe manner.

We also order the continued tracking of incremental costs incurred due to the steam generator outages for further review in Phase 3 when the Commission examines the Steam Generator replacement project as a whole. The Utilities shall cease collection of these incremental costs, and these funds shall be separately accounted for, including interest paid as of June 1, 2012 on recorded SGIR-related O&M and capital costs, if already collected in rates.

The Phase 1A portion of today's decision adopts a method for calculating the cost of replacement power in 2012, and orders the utilities to serve exhibits detailing their calculations according to the adopted method. Recovery of the calculated replacement power costs will be decided in Phase 3 of this proceeding.

2. Background

The San Onofre Nuclear Generating Station (SONGS), located adjacent to Camp Pendleton near San Clemente California, is jointly owned by Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and the City of Riverside (with shares of 78%, 20% and 2% respectively).[2] SCE is the plant operator and bills co-owners for their share of costs.

Pursuant to SCE's 2004 application,[3] the Commission authorized the replacement of the four steam generators at SONGS Unit 2 (U2) and Unit 3 (U3),[4] to be followed by utility applications for reasonableness review of the project costs after completion.[5] Mitsubishi Heavy Industries (MHI) designed and

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[2] The City of Riverside is a municipal utility not under the California Public Utilities Commission's (Commission's) jurisdiction.

[3] Application (A.) 04-02-026.

[4] SONGS Unit 1 has been decommissioned.

[5] Decision (D.) 05-12-040 at Ordering Paragraph (OP) 11, as modified by D.11-05-035.

manufactured the replacement steam generators. The steam generators in U2 were replaced and put online in January 2010; U3 steam generators were replaced and put online in January 2011. In reliance on the Commission's decision approving the Steam Generator Replacement Project (SGRP), both Utilities began to recover a portion of the originally approved costs in 2011.

On January 10, 2012, U2 was taken out of service for a scheduled Refueling Outage (RFO) and expected to return to service on March 5, 2012. U3 was taken offline on January 31, 2012, after station operators detected a radiation leak in a steam generator tube. U2 and U3 were offline throughout the rest of 2012. On June 7, 2013, SCE announced it would not seek to restart either SONGS unit.

In February 2012, the first of many inspections and tests identified different types of tube wear in the U2 and U3 steam generators. SCE engaged with the U.S. Nuclear Regulatory Commission (NRC) following the discovery in U3, and NRC conducted an audit of the problem. SCE also undertook its own investigations and inspections. An unknown phenomena, known as tube-to-tube wear was observed in both U2 and U3 by April 27, 2012.

SCE rescheduled the date for completion of the U2 RFO from March 4, 2012 to March 20, 2012, the first of many delays. SCE identified all compromised, or potentially compromised, tubes and plugged or stabilized them. However, the NRC did not allow SCE to restart the units, even at reduced power, during 2012, or thereafter.

As part of their 2012 General Rate Case (GRC), SCE initially sought approval of its total forecast 2012 SONGS-related expenses based on ordinary operating conditions.[6] SCE estimated $389 million ($2012) for 2012 Operations & Maintenance (O&M) (100%), and $189 million for capital expenditures, as well as $45.0 million for each of two scheduled refueling outages. SDG&E requested rate recovery of its 20% pro rata share through its 2012 GRC, in addition to capital costs and other internal SONGS-related expenses.

Both SCE's and SDG&E's GRCs were pending during 2012. However, the evidentiary records closed well before the year ended and all facts were known. During 2012, SCE incurred O&M costs and capital spending even as it became clear that the units would not be restored to service in 2012, a critical change in circumstance. The Commission decided to review all actual 2012 expenses associated with the non-productive plant after they became known, including SCE's operational response to the extended outages.

Pursuant to Public Utilities Code Section 455.5, on November, 1, 2012, the Commission issued an Order Instituting Investigation (OII)[7]:

> This investigation will consider the causes of the outages, the utilities' responses, the future of the SONGS units, and the resulting effects on the provision of safe and reliable electric service at just and reasonable rates.[8]

The OII ordered SCE and SDG&E to each establish a SONGS Outage Memorandum Account (SONGSMA) to track by category all SONGS-related costs and expenditures incurred on or after January 1, 2012, and revenues collected in recovery of those costs. The Utilities were required to categorize

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[6] A.10-11-015.

[7] Unless otherwise indicated, all future statutory references refer to the Public Utilities Code.

[8] Order Instituting Investigation (I.) 12-10-013 at 2.

recorded expenses by certain subaccounts to identify, inter alia, fixed costs, variable costs, SGRP costs, investigation costs, safety-related program costs, replacement generation, repair costs, regulatory costs, etc.[9] A copy of SCE's year-end 2012 report on the SONGSMA (SCE share) is attached hereto as Appendix A; a copy of SDG&E's year-end reports is attached as Appendix B.

In the GRC decisions for both Utilities, the Commission concluded it was in the best interests of ratepayers to preliminarily allow SONGS-related 2012 O&M and capital expenditures that would have been authorized under normal operating conditions. We anticipated that SCE would need to maintain some systems (e.g., cooling) and divisions (e.g., security, environmental safety) in 2012, regardless of operating conditions, as well as apply resources to understand and address the effects and conditions it faced for the future.

We deferred the final reasonable reviews to the OII and ordered these 2012 costs subject to refund. In Decision (D.) 12-11-051, the Commission confirmed its order to SCE and SDG&E to establish memorandum accounts to be harmonized with the OII, for the purpose of tracking all post-2011 SONGS-related costs for subsequent review. Consistent with the OII, the Commission imposed similar orders in the SDG&E GRC decision.[10]

Following the U3 outage, SCE incurred inspection and repair costs for U2 and U3, while it claimed to be developing a short-term restart plan for U2 and exploring long-term plans for both units. These costs are distinct from Base

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[9] The Utilities developed a common format but SCE claims it cannot segregate "safety-related" costs on the basis that safety activities cross several budgets and cannot be reasonably identified.

[10] D.13-05-010.

(routine) O&M. In 2012, both SCE and SDG&E also had to purchase power to replace power lost due to the SONGS outages. The methodology to calculate the amount of replacement power purchased is established below.

3. Procedural History

On November 1, 2012, the Commission opened this OII to consolidate and consider issues raised by the extended outages of SONGS U2 and U3.

The OII identified rate recovery issues including: (1) review of all post-2011 O&M costs and capital spending; (2) costs of scheduled RF) and emergent activities; (3) removal of non-useful generation assets from rate base; and (4) various questions around the costs, viability, and prudency of the SGRP approved in D.05-12-040.

Within the OII, the Commission stated its intention to consolidate other proceedings, to be initiated in the future, which would encompass review of the full range of post-outage costs and activities.[11] Subsequently, SCE and SDG&E have each filed applications for reasonableness review of 2012 recorded O&M and capital spending,[12] for approval of the totality of the SGRP costs,[13] and for power purchased during 2012, including replacement of power lost due to the outages.[14] The Utilities seek rate recovery from ratepayers for all of these expenses.

A prehearing conference (PHC) was held on January 12, 2013. The assigned Commissioner and Administrative Law Judge (ALJ) determined that to

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[11] OII at 8.

[12] A.13-01-016 (SCE), A.13-03-013 (SDG&E).

[13] A.13-03-005 (SCE), A.13-03-014 (SDG&E).

[14] A.13-04-001 (SCE).

promote the efficient administration of the OII, it would be divided into several phases, each with its own PHC and Scoping Memo. Among the benefits of this approach are: (i) the building of a chronological record, (ii) pacing for certain information not yet known, and (iii) consistent decisions in future phases.

On January 28, 2013 assigned Commissioner Michel Peter Florio and ALJ Melanie M. Darling[15] issued a scoping memo for Phase 1, set dates for parties to serve testimony, and established dates for evidentiary hearings in Phase 1. The Phase 1 scope is as follows:

1. Nature and effects of the steam generator failures in order to assess the reasonableness of SCE's consequential actions and expenditures;
2. Whether 2012 SONGS-related O&M expenses and capital expenditures recorded in the SONGSMA are reasonable and necessary, including:
   - 100% of cost-savings from personnel reductions and other avoided costs; and
   - 100% of refueling outage expenses;
3. A review of the reasonableness and effectiveness of SCE's 2012 actions and expenditures for community outreach and emergency preparedness related to the SONGS outages; and
4. Other issues as necessary to determine whether SCE should refund any rates preliminarily authorized in the 2012 GRC, in light of the changed facts and circumstances of the unit outages; if so, when should the refunds occur.

SCE's and SDG&E's applications for review of 2012 O&M costs and capital expenditures recorded in the SONGS Memorandum Accounts, consolidated with

[15] On May 1, 2013, ALJ Kevin Dudney was co-assigned to the OII.

the OII, are the primary focus of review in Phase 1. These proceedings were consolidated with the OII in April, 2013.[16]

In response to the OII, SCE and SDG&E both argued the Commission lacked authority to (1) review and refund 2012 estimates of O&M and capital spending, as deferred by the GRC decision; and (2) remove any SONGS assets and associated O&M from rate base pursuant to § 455.5, prior to SCE's 2015 GRC. The Scoping Memo directed parties to brief these legal issues.

An April 30, 2013 Assigned Commissioner and Administrative Law Judge Ruling resolved these questions. As it relates to Phase 1, the Commission ruled that it has legal authority to conduct the deferred final reasonableness review of SONGS-related expenses (100%) sought in SCE's 2012 GRC and immediately order refunds, if warranted.[17]

Therefore, Phase 1 identifies what SONGS-related costs SCE and SDG&E incurred in 2012, and how should they be categorized, e.g., base (GRC) O&M, base capital expenditures, RFO base costs and emergent work, incremental and consequential steam generator inspection and repair costs. In addition, Phase 1 considers the reasonableness of the various identified 2012 costs given the facts and circumstances SCE knew, or should have known, at the time the costs were incurred. Finally, Phase 1 determines whether refunds should be issued to ratepayers for overcollections in 2012.

By e-mail ruling on May 3, 2013, the assigned ALJs created a sub-phase, called Phase 1A, to develop a method for calculating 2012 costs of replacement

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[16] Ruling dated April 19, 2013.

[17] Assigned Commissioner's and Administrative Law Judge's Ruling on Legal Questions (April 30, 2012) at 17.

power. Although the ALJs announced that they intended to resolve Phase 1A issues by a ruling, we have decided to resolve both Phase 1 and Phase 1A issues in today's decision.

Several parties participated in Phase 1 and Phase 1A by serving testimony, conducting cross-examination of witnesses, and/or filing post-hearing briefs. In addition to SCE and SDG&E, these parties are Division of Ratepayer Advocates (DRA),[18] The Utility Reform Network (TURN), Alliance for Nuclear Responsibility (A4NR), World Business Academy (WBA), Women's Energy Matters (WEM), Joint Parties (comprised of National Asian American Coalition, Ecumenical Center for Black Church Studies, Latino Business Chamber of Greater Los Angeles and Chinese American Institute for Empowerment), and the Coalition to Decommission San Onofre (CDSO).

Motions to alter the Scoping Memo, to immediately order refunds, strike testimony, etc. have been filed and ruled upon, none of which altered the course of the OII set forth in the Scoping Memo, except to clarify that ordinary review of power purchases by both Utilities would continue to occur in their respective Energy Resource Recovery Account (ERRA) proceedings.

Evidentiary hearings in Phase 1 were held from May 13 to 17, 2013. During examination of SCE witnesses, it was disclosed that SCE had identified "Base" O&M costs by timing each month, rather than by actual purpose of the expense. At the end of the hearings, SCE and SDG&E each agreed to provide an exhibit with a revised breakdown of 2012 costs by month, segregated as to Base O&M and costs incurred as a result of the outages. As a result, on July 22, 2013,

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[18] Now known as the Office of Ratepayer Advocates.

SCE served SCE-35 and SDG&E served SDGE-11. These exhibits are accepted into the proceeding record.

Phase 1 Opening Briefs and Reply Briefs were filed by SCE, SDG&E, DRA, TURN, A4NR, WBA, CDSO, Joint Parties and WEM on June 28, 2013 and July 9, 2013, respectively.

Evidentiary hearings in Phase 1A were held on August 5 and 6, 2013. SDG&E served late-filed exhibit SDGE-17 on August 9, 2013, which is an errata to SDG&E's 2012 SONGS Outage Memorandum Account (SONGSMA). This exhibit is admitted into the proceeding record.

Phase 1A Opening Briefs were filed on August 29, 2013 by SCE, SDG&E, DRA, and A4NR. Phase 1A Reply Briefs were filed by SCE, SDG&E, TURN, A4NR, DRA, and WEM.

The matter, including both Phase 1 and Phase 1A, is submitted as of September 12, 2013.

4. Standard of Review

Phase 1 is in essence a ratesetting action and the standard of review for rate recovery is the preponderance of evidence.[19] Despite A4NR's reference to dated Commission decisions which used the term "clear and convincing," this legal standard has been explicitly rejected by the Commission.[20] We are not persuaded by A4NR's argument that SCE's conduct has been found to be so imprudent in its response to the outages that the higher burden of proof should apply. The Commission has not made any finding of imprudence in the Phases

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[19] D.12-11-051.

[20] D.11-05-018 at 34.

resolved in this decision. Instead, the test is whether SCE's 2012 actions as the SONGS operator, were reasonable and prudent.

A4NR and SDG&E both emphasized past Commission findings which evaluated the reasonableness of operational decisions. As affirmed by SDG&E, SCE must show that its decision-making process was sound, its managers considered a range of options in light of information that SCE knew or should have known, and decided on an action within the bounds of reasonableness.[21]

A4NR recalls the Commission's prior finding that "a 'reasonable and prudent' act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction."[22]

This standard of reasonableness does not derive from the consequences of managerial action, but the soundness of the utility's decision-making process that led to the decision and the consequences.[23]

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[21] SDG&E Opening Brief (OB) at 3.

[22] A4NR OB at 7 (citing D.05-08-037 at 4-5).

[23] D.05-08-037 at 4-5 (citing D. 89-02-074) ("a decision may be found to be reasonable and prudent if the utility shows that its decision making process was sound, that its managers considered a range of possible options in light of information that was or should have been available to them, and that its managers decided on a course of action that fell within the bounds of reasonableness, even if it turns out not to have led to the best possible outcome").

5. Parties' General Positions

5.1. Utilities

SCE and SDG&E seek a finding that all of the 2012 SONGS-related recorded expenses are reasonable under the circumstances, and request Commission approval to recover 100% of the expenses in rates.

In addition to testimony provided in these proceedings, each utility has regularly provided the Commission with reports of recorded SONGS-related costs, pursuant to the OII.[24] As a result of accounting anomalies revealed, each utility provided a further breakdown of recorded "Routine" O&M between "Base-Routine" and "Base-SGIR" costs after the evidentiary hearings concluded.[25]

In 2012, SCE recorded its share of total "routine" O&M and capital costs of $520.2 million ($2012), plus an additional $139.8 million for the U2 RFO, seismic study costs, and SG Base and Inspection and Repair (SGIR) costs.[26] SCE recorded total (100% share) capital expenditures of $167.6 million, of which the SCE share is $131.08 million.[27] SGIR-related capital expenditures by SCE total $13.9 million.

SDG&E claims its total share of comparable 2012 costs is $133.47 million,[28] plus an additional $36.288 million for the U2 RFO, seismic study costs, and SGIR

[24] SCE provides monthly reports, SDG&E provides quarterly reports.

[25] SCE-35; SDG&E-11.

[26] Appendix A, SCE Monthly Report filed in compliance with I.12-10-013 (February 1, 2013).

[27] SCE-04 at 87-88 (SCE recorded $133.606 million which includes $2.5 million for SCE's share of license renewal-related expenditures not claimed for recovery).

[28] Includes an adjustment of $694,000 based on difference between Routine O&M in 1Q2013 SDG&E Quarterly Report filed in compliance with I.12-10-013 (April 2, 2013) and SDG&E-11 ($73.559 - $72.865 million = <0.694 million>).

costs.[29] SDG&E recorded capital expenditures of $39.3 million invoiced by SCE, and an additional $10 million for its own overheads.[30] The capital expenditures for SGIR are not quantified.[31]

SCE contends that, in light of the nature of the steam generator failures, its consequential actions and expenditures during 2012 were reasonable, including completion of U2 refueling activities and all costs related to inspection and repair of the steam generators (SGIR). Although both SONGS units were in extended outages as a result of the tube problems in both units, SCE argues that SONGS was an operating facility in 2012.[32]

As operating agent, SCE states it was required to ensure that all plant systems remained functional to protect the nuclear fuel and to ensure the radiological health and safety of the public and workers. Systems were maintained, rather than be allowed to deteriorate, to prepare for resumed operations.

In addition, SCE claims it postponed or canceled some capital projects and O&M activity when it was possible "without compromising regulatory and safety-related objectives."[33] Furthermore, SCE asserts it would have been imprudent not to undertake actions to investigate the causes of the damage to the units, and to develop plans to return the units to service in the long-term.[34]

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[29] SDG&E-3 at 12; SDG&E-11 at 3.

[30] *Id.*, Work papers at 3.

[31] SDG&E-3 at 9; SDG&E 3-Workpapers at 3.

[32] SCE OB at 1.

[33] *Ibid.*

[34] *Ibid.*

Therefore, SCE asks the Commission to find that it acted reasonably in 2012 in taking actions to maintain systems, structures, components, and other processes and procedures as required by its operating licenses, and to restore the units safely to service. SCE also asks the Commission find that 100% of 2012 expenses recorded in the SONGSMA were reasonably incurred, and to allow full rate recovery.

SDG&E agrees with SCE, primarily because it relies on SCE to undertake decision-making and activities consistent with the terms of the Operating Agreement[35] and the NRC license.[36] SCE states that it "is unaware of any material facts or representation made by SCE during Phase 1 that would contradict SCE's written testimony or data responses pertaining to its consequential actions, the timing thereof, and the resulting expenditures in 2012 in light of the steam generator failures."[37]

SDG&E requests similar treatment for its share of total SONGS-related expenses recorded by SCE, and approval of approximately $60.5 million in other 2012 GRC costs for which the Commission deferred reasonableness review to this proceeding.[38] Although the extra SDG&E expenditures occur regardless of whether SONGS generates electricity, SDG&E claims they are required as a result of its ownership of SONGS. Therefore, SDG&E requests that these 2012

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[35] SCE and the other co-owners have executed an Operating Agreement covering the terms and conditions for operations and pro rata recovery of costs.

[36] SDG&E OB at 3.

[37] *Ibid.*

[38] D.13-05-010 (A.10-12-006).

incurred expenses associated with these activities be found reasonable, prudently incurred and recoverable from ratepayers

5.2. Division of Ratepayer Advocates (now known as Office of Ratepayer Advocates)

DRA disagrees that SCE has established any 2012 SONGS costs were reasonably incurred in 2012. Instead, DRA argues the Commission cannot conduct a reasonableness review of SCE's SONGS-related 2012 expenses, should not allow rate recovery at this time, and should promptly order refunds of "unnecessary" charges associated with SONGS.[39] DRA explains that "unnecessary" charges include revenue requirement collected in excess of actual expenses, but does not quantify what it considers "necessary" or "unnecessary."

DRA has "no objection" to eventual recovery of "verifiable" safety and security-related 2012 costs, but argues that SCE did not establish those actual expenses, e.g., no segregated safety expenses, no workpapers to support security expenses.[40] Moreover, DRA concludes there is insufficient evidence to support a Commission finding that SCE's 2012 actions and expenditures in connection with the steam generator failures were reasonable.[41] As to these costs, DRA recommends that the Commission defer any such finding until completion of the NRC's investigations into SONGS Units 2 and 3 and key facts about third party cost recovery are known.[42] One of DRA's witnesses went further and stated that no recovery should be allowed at all, because SCE can obtain recovery from MHI

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[39] DRA OB at 12.

[40] *Id.* at 11.

[41] *Id.* at 6.

[42] *Id.* at 7.

or through insurance and it would prompt more shareholder oversight of management. [43]

5.3. The Utility Reform Network

TURN, similar to other non-utility parties, argued that "incremental" costs resulting from the steam generator failures should be removed from the SONGSMA and denied rate recovery here.[44] TURN asserts the incremental costs lack any presumption of reasonableness since they are "the direct result of imprudence by SCE and/or its vendors…."[45] Instead, TURN would remove all SGIR-related expenses from the SONGSMA and require a separate application for review.

TURN identified certain cost categories it agreed should be tracked in the SONGSMA (e.g., pre-core fuel inventory, materials and supplies inventory, cash working capital attributable to SONGS, third party payments), but found SCE's testimony "murky" and seeks further clarification for particular cost categories. TURN would limit utility rate recovery here to "unavoidable expenditures required to maintain the plant and meet minimum federal license requirements."[46] For example, "Base-Routine" O&M costs in the SONGSMA should be subject to reasonableness review, and TURN would cap recovery at the final levels identified by the utilities in Phase 1.[47]

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[43] TR at 992-993.

[44] TURN OB at 5.

[45] *Id.* at 7.

[46] *Id.* at 5.

[47] *Ibid.*

In addition, TURN recommends the Commission adopt a presumption that all Construction Work In Progress (CWIP) as of December 31, 2012 is abandoned plant, ineligible for accrued Allowance for Funds Used During Construction (AFUDC).[48] However, TURN suggests an exception for capital projects which SCE can show are necessary to maintain safety at the facility under permanent shutdown.

TURN also posits that the SONSGMA does not accurately capture all SONGS-related costs. TURN points to SCE's failure to provide a SONGS-only cash working capital (CWC) calculation, separate from its overall utility-wide CWC, including separate SONGS-only lead lag calculations, leading to an unacceptable omission of costs.[49]

TURN also asks the Commission to suspend SCE's authority to collect any future revenues for seismic studies related to the relicensing of the plant and eliminate any seismic O&M expenditures already incurred in Edison balancing accounts in current rates

5.4. Alliance for Nuclear Responsibility

A4NR rejects rate recovery for any 2012 SONGS-related expenses. As soon as SCE became aware of the extent of vibratory damage to the steam generator tubes in both units, A4NR argues that SCE should have decided to shut down permanently. A4NR concludes that SCE should have known the costs to repair or replace the steam generators, in light of about $1 billion of plant still in rate

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[48] *Id.* at 10.

[49] *Id.* at 14.

base, rendered any action other than immediate shutdown to be economically unreasonable.[50]

Based on SCE's proffered evidence of what it knew, or should have known, about the condition of the U2 and U3 steam generators in the immediate aftermath of the January 31, 2012 tube leak, A4NR asserts it is impossible to characterize the managerial decision making as sound, logical, reasonable, or prudent. A4NR also questions SCE's characterization of the most extensive types of wear in U2 as "manageable," an assumption that led to the U2 restart plan.

Furthermore, asserts A4NR, SCE's witnesses provided no evidence its managers considered a range of possible options in light of the information that was or should have been available to them. Because SCE failed to show why the decision to permanently shut down could not, and should not, have been made early in 2012, A4NR concludes that all subsequent facility-related rates are over-collections and should be refunded.[51]

5.5. World Business Academy

WBA assumes that sometime in 2012, SCE knew or should have known the SONGS facility would never restart or produce electricity again. Because SONGS is now permanently out of service, and has provided no power since January 2012, WBA urges the Commission to immediately refund 100% of 2012 SONGS costs retroactively to that date.[52] WBA contends SCE did not show that

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50 A4NR OB at 2.

51 *Ibid.*

52 WBA-1 at 3.

its 2012 SONGS- related costs were just and reasonable, and delaying the return of revenues unjustly collected will continue to harm ratepayers.[53]

WBA claims SCE failed to meet its burden of proof because its testimony was largely conclusory, "offering broad narratives unsupported by the requisite degree of specificity and detailed explanation" (except for emergency preparedness).[54] Although WBA signals openness to rate recovery for costs and capital expenditures specifically related to ensuring safety of the plant, it found SCE's testimony "contradictory" and lacking in any uniform definition of "safety-related."

WBA focuses on SCE's claimed inability to segregate "safety-related" costs, and surmises SCE preferred to characterize all costs as safety-related in order to maximize recovery. As an alternative, WBA recommends the Commission order a third-party financial audit to identify all 2012 safety-related expenses for a final reasonableness determination.

Additionally, WBA contends that SCE and MHI are objectively at fault for the SONGS shut-down and third-party payments should cover consequential costs instead of ratepayers.[55] Finally, SCE did not demonstrate the reasonableness of its 2012 incremental costs to investigate the causes of the tube wear, develop a plan to return U2 to service at 70% power, and place U3 in an extended shutdown condition.[56]

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[53] WBA OB at 1.

[54] *Id.* at 3.

[55] WBA-1 at 5, 16.

[56] WBA OB at 10.

5.6. Women's Energy Matters

WEM opposes rate recovery for all 2012 SONGS-related costs, including the U2 RFO. WEM 's position is premised on the view that SCE knew the steam generators were "experimental" and knew or should have known they were irreparably damaged at the first inspection during the U2 RFO.[57] Instead of going to permanent shutdown, states WEM, SCE engaged in a futile and expensive set of activities to try to support the restart of U2. SCE's failure to undertake a cost-effectiveness analysis of the restart plan is further evidence of its unreasonable course of action, claims WEM.[58]

WEM argues that the only 2012 SONGS-related costs that might be reasonable to recover from ratepayers are those incurred in January, subject to refund if SCE is later found to have been imprudent or "committed fraud" regarding the SGRP.[59] Similar to TURN, WEM also contends some costs are missing from the SONGSMA because they are "buried" in other company budgets.

For example, WEM specifically identifies Community Outreach and Emergency Planning, Education, and Philanthropy[60] as one such area, along with Regulatory Affairs, and Information Technology support. WEM opposes all funding for Community Outreach activities which it views as functionally corporate public relations and designed to mislead, rather than educate, the

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[57] WEM OB at 6.

[58] *Id.* at 11.

[59] *Id.* at 3.

[60] Utility philanthropy is not funded by ratepayers.

public.[61] WEM states it would only support cost recovery, if SCE expands emergency planning and public education beyond the minimum requirements of the NRC and Federal Emergency Management Agency.

5.7. Coalition to Decommission San Onofre

CDSO also favors immediate refunds of SONGS expenses collected in rates, and opposes ratepayer funding of any 2012 SONGS-related costs, except costs required to maintain safety-related components of the plant, as defined by the NRC.[62] Consequently, CDSO opposes rate recovery for any RFO and SGIR expenses.

CDSO asks the Commission to order SCE to identify the NRC-defined "systems, structures and components, and procedures and processes that are absolutely necessary in emergency, non-routine conditions to safely shutdown the plant and maintain it in a safe shutdown condition," and associated costs.[63] A public workshop run by the Energy Division is CDSO's suggested form of SONGSMA cost review.

Underlying CDSO's position is its allegation that SCE "deliberately misrepresented the SGRP to the NRC, the Commission, and the public, and knew the moment it discovered tube wear during the U2 RFO, that repairs were imprudent.[64] Furthermore, CDSO criticizes SCE for a failure to consider the

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[61] WEM-8 at 9.

[62] CDSO OB at 4.

[63] *Ibid.*

[64] CDSO OB at 5.

safety or costs of alternative solutions to the U2 restart. Instead, asserts CDSO, SCE should have moved both units to preservation mode in June.

Based on the Augmented Inspection Team (AIT) Report which identifies several "more than minor" procedure violations, CDSO claims ratepayers should not pay for (unspecified) non-compliant operations. The group also argues SCE's Community Outreach and Education costs are not reasonable because SCE does not comply with state law requiring a 35-mile radius for its public education zone.

5.8. Joint Parties

Joint Parties focused on Community Outreach and Education activities (in company-wide O&M), and criticize SCE for not taking "appropriate steps" to educate and inform a diverse population in the service territory surrounding SONGS.[65] One particular area of concern is that SCE does not specifically track the costs related to "SONGS outreach" which, according to Joint Parties, prevents the Commission and parties from fully evaluating SCE's actions and expenditures.[66]

Joint Parties specifically criticize some outreach activities, such as those conducted on weekdays when people with "regular jobs" cannot attend, or a Rotary Club presentation because it does not reach "the underserved.[67]" On a broader point, the group views many of SCE's outreach activities as primarily

[65] Joint Parties OB at 8.

[66] *Id.* at 4.

[67] *Id.* at 4-5.

about improving SCE's corporate image, instead of providing public education about SONGS.

Joint Parties asks the Commission to order SCE to provide an accounting for these costs and, that an employee be designated to coordinate all of the public education and community outreach efforts for SONGS.[68] The Commission should then defer its reasonableness review of these costs until the accounting is provided, and costs that benefit corporate image should be disallowed.

Other recommendations from Joint Parties are that SCE should be ordered to:

- expand the reach of its public education effort to be a 20-50 mile radius from SONGS;
- ensure that all community outreach, education, marketing, and external relations related to SONGS are, from this point forward, universally provided in Vietnamese, Korean, Khmer/Cambodian, Chinese, Tagalog, and Spanish; and
- conduct a comprehensive survey of communities within 20 miles of SONGS to ascertain residents' attitudes and knowledge regarding nuclear power and SONGS.[69]

6. What SCE Knew or Should Have Known

As a starting point for determining whether SCE's decision-making process was sound, the Commission examined the NRC's Confirmatory Action Letter (CAL)[70] and the NRC's AIT Report for the sequence of events and known facts, and an independent assessment of SCE's actions from NRC's on-site inspectors.

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[68] *Id.* at 5.

[69] *Id.* at 9-10.

[70] Appendix 2 to SCE-02 and SCE-03, Tabs 2, 25.

SCE provided a chronology of key operational facts and significant dates in 2012 related to the outages.[71] Based on the record, other dates and some information has been added to the timeline, which is attached as Appendix C. This chronology also assisted the Commission in its review of the reasonableness of SCE's actions and recorded expenses during 2012.

Both U2 and U3 were in their first cycle of operation with new replacement steam generators. Each replacement steam generator (SG) has 9,727 tubes, two SGs per Unit. In the straight-leg portion of the tubes, the tubes are supported by a series of tube support plates (TSP) through which the tubes penetrate. The U-bend region is located at the top of the tube bundle and is supported by an anti-vibration bar (AVB).[72]

According to SCE, and elsewhere in the record, SG tubes have historically experienced tube degradation related to various phenomena. These degradation mechanisms can impair tube integrity if they are not managed effectively. SCE states that when the degradation of the tube wall reaches a prescribed repair criterion, the tube is considered defective and corrective action must be taken.[73]

Based on the CAL, AIT Report, and SCE's testimony, we are persuaded by a preponderance of evidence that SCE knew or should have known the following:

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[71] SCE-10 at Q4.

[72] SCE-04 at 77-78.

[73] *Id.* at 79.

- On January 31, 2012 when the U3 leak was discovered, U2 was about half-way through its scheduled refueling outage where significant inspections, testing, and repairs take place.[74]
- AIT found that SCE plant operators responded to the January 31, 2012, SG tube leak in accordance with procedures and in a manner that protected public health and safety. Plant safety systems also worked as expected during the event.[75]
- In early February, SCE's routine eddy current testing[76] of U2 tubes identified 2,411 tubes with indications (most less than 20%) of tube wear attributable to retainer bar wear, support plate wear, or AVB. SCE plugged six damaged tubes and another 182 tubes were plugged as a precaution.[77]
- AIT considered the U2 wear indications found similar to those found at other replacement steam generators after one cycle of operation.[78]
- On February 12, 2012, SCE inspection confirms leak in U3 SG tube; eddy current testing identifies unexpected retainer bar wear, similar to U2, and significant Tube-to-Tube wear (TTW) in the U-tube region of the SG.[79]

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[74] SONGS--NRC Augmented Inspection Team Report 05000361/20122007 and 05000362/20122007 (June 18, 2012) (AIT Report), § 1.1.

[75] *Id.* at Executive Summary.

[76] Eddy current testing involves inserting a probe into each tube and measuring the tube wall thickness throughout the full length of the tube through the use of electromagnetic signals.

[77] AIT Report at § 1.4.

[78] *Id.* at § 1.4 (A total of 2411 tubes were found with indications at the tube support plates and anti-vibration bar supports, the vast majority of which had a measured depth of less than 20 percent of the tube wall thickness).

[79] *Id.* at § 1.1

- On March 13, 2012, eight U3 tubes failed additional in-situ pressure testing by SCE's consultant (AREVA), of 129 tubes that showed the most wear.[80]
- AIT stated failure of U3 in-situ pressure test is an indication that, for certain design basis events, such as main steam line break, these SG tubes may not be able to maintain structural integrity.[81]
- On March 19-29, 2012, AIT was on-site conducting its inspections. MHI and SCE were onsite conducting cause evaluations for the tube failures and unexpected wear in U3.[82]
- On March 23, 2012, SCE submitted SG Return-to-Service (RTS) Action Plan to NRC outlining its commitments to corrective actions before restarting either unit.[83]
- On March 27, 2012, NRC sent SCE a CAL that notified SCE it may not restart either unit until SCE completes a list of actions and NRC completes its review of the actions, including:
  - ✓ Determine causes of TTW; plug all tubes with significant wear.
  - ✓ Submit written results of SG assessments for both units, proposed inspection protocols, schedule for a mid-cycle shutdown, and basis for SCE's conclusion thatU2 will safely operate as required by NRC regulations.
  - ✓ The CAL will remain in effect until the NRC has (1) reviewed SCE's response, including responses to staff questions and the results of SCE's evaluations, and (2) NRC has written its

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[80] U.S. Nuclear Regulatory Commission Confirmatory Action Letter to SCE (March 27, 2012) (CAL) at 1.

[81] *Ibid*.

[82] *Id*. at § 2.0.

[83] SCE-10 at Q4.

conclusion that the units can operate safely without undue risk to public health and safety, and the environment.[84]

- In March 2012, SCE developed a plan to postpone, cancel, and re-schedule capital projects; SCE also began work on short-term and long-term repair options.[85]
- On April 10, 2012, SCE identified two tubes with TTW in the U3 free-span U-bend region, where U2 TTW was found.[86]
- Regarding SCE's extensive U3 eddy current testing completed April 15, 2012, more than half of the TTW indications in each SG had maximum measured depths exceeding the 35% plugging limit in the technical specifications, and ranged to as much as 99%.[87]
  - ✓ Over 460 tubes in each SG had wear indications at the tube support plates; about 170 tubes in each SG exhibited indications at the tube support plates that exceeded the 35% plugging limit.[88]
  - ✓ Approximately 800 tubes in U3 SGs exhibited wear indications at the AVB supports; most measured less than 20%, only two exceeded the 35% plugging limit.[89]
  - ✓ Four tubes with retainer bar wear indications were plugged and stabilized; the remaining 184 tubes that intersect the retainer bars were plugged as a preventative measure.[90]

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84 CAL at 2-3.

85 TR at 714.

86 AIT Report at § 1.4.

87 AIT Report at § 1.5.

88 *Ibid.*

89 *Ibid.*

90 *Ibid.*

- On April 23, 2012, SCE issued U2 tube wear Root Cause Analysis (RCA) which identified the cause of TTW as Fluid Elastic Instability (FEI).[91]
- On April 26, 2012, SCE Board of Directors was told that U2 RTS was scheduled for 6/1, and U3 on 6/30, after SCE responded to the CAL.[92]
- On May 7, 2012, SCE issued U3 RCA which included identification of TTW in U2 and U3.[93]
- In March/April and May/June, SCE was able to fully characterize the conditions at U2 and U3, respectively, and focus on responding to TTW.[94]
- On June 18, 2012, the NRC held a public meeting and presented the AIT Report to SCE executives who acknowledged the findings, including:
  - ✓ NRC team identified ten "unresolved" items requiring additional review for regulatory action.
  - ✓ SCE was adequately pursuing the causes of the unexpected TTW degradation; SCE retained a significant number of outside industry experts, consultants, and SG manufacturers to perform modeling and analysis.
  - ✓ SCE was adequately pursuing the causes of the unexpected steam generator tube-to-tube degradation. SCE retained a significant number of outside industry experts, consultants, and steam generator manufacturers, including Westinghouse

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91 SCE-04 at 82.

92 A4NR-5 at 2.

93 SCE-10 at Q4.

94 TR at 772.

and AREVA to perform thermal -hydraulic and flow induced vibration modeling and analysis.[95]

- In June 2012, SCE began planning to put U3 into Preservation Mode.[96]
- On June 12, 2012 MHI issued its technical RCA.
- On June 18, 2012, NRC presented AIT Report Exit at public meeting.
- In July 2012, SCE created a long term repair team for both units to develop options with MHI.
- On October 3, 2012, SCE submitted Response to CAL; NRC identifies 6 -7 month window for review, inspections, response to staff information requests, public meetings, etc.
- On November 11. 2012, NRC issued draft Report of vendor inspection at MHI: two notices of non-conformance re Quality Assurance issues.
- On December 5, 2012, the Atomic Safety Licensing Safety Board held hearing to determine whether SCE will need a license amendment to try U2 restart plan.
- On December 14, 2012, MHI sends two progress letters to SCE regarding development of long-term repair options.[97]
- December 20, 2012, MHI provides long-term repair options and recommendations.[98]

6.1. Discussion

This discussion draws inferences as to what SCE knew in 2012 based on the facts as they unfolded and became known to SCE. The non-utility parties

[95] AIT Report at § 14.

[96] SCE-10 at Q4.

[97] SCE-16, SCE-17.

[98] SCE-15.

argue from the assumption that SCE entered 2012 with pre-existing knowledge about risks and problems with the design and/or operations of the replacement steam generators arising from the inception of the project in 2004. However, the SGRP was approved by the Commission in 2005, rate recovery authorized upon completion, and a presumption of reasonableness applied if costs remained below forecasts.

Therefore, in this phase, we confine our review to knowledge gained by SCE in 2012 which informed, or should have informed, SCE's decisions in how to respond to the SG problems. In Phase 3, we will examine the SGRP as a whole and, if it is established that SCE had pre-existing knowledge about risks at the SGs, then it is possible that some or all SGIR-related expenses in 2012 may be found unreasonable.

During January and February, the Commission finds that SCE acted as a prudent operator of a generation facility to detect the U3 leak, identify the source of the leak, inspect all of the U2 and U3 tubes for damage, investigate the causes of excessive and unexpected wear, and to assess whether repair is a reasonable option. SCE first knew about both excessive wear in both units and the unique phenomena of TTW in U3 in mid-March. This raised the question of whether there was a design, installation, or operation problem, and whether it was fixable, and if SCE bore any fault. SCE considered TTW as the most significant and complex phenomena, and a key barrier to restart of U2.[99]

SCE understood that the units were likely to be offline for some time, because SCE developed a plan in March to postpone, cancel, and re-schedule

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[99] TR at 735.

capital projects and began work on short-term and long-term repair options. SCE also notified the NRC in March of its decision to restart U2, before understanding the causes of TTW, whether it existed in U2, or what repair options were viable. The NRC responded by prohibiting either unit from restart until SCE received written permission from the NRC.

By April, SCE was able to fully characterize the conditions at U2 and focus on responding to TTW, as the other wear was "manageable."[100] SCE understood from its own RCA issued in April, that the cause of the unprecedented TTW wear was a previously unknown condition: Fluid Elastic Instability (FEI). However, at least by May 7, when SCE confirmed by its own analysis that both units had TTW, SCE knew the fix for FEI was not going to be quick. The U2 RTS date continued to slip.

Nonetheless, SCE states it had high confidence U2 would restart in 2012, and decided to maintain readiness to operate, despite costs that amounted to about $1 million per day.[101] The assumption was "an important assumption in terms of how we prioritize work for the plant staff, the operators, and others".[102] At an April 26 meeting of the Board of Directors, SCE managers unrealistically advised the Board that U2 could return to service by June 1, and U3 by June 30.[103] These projections were unrealistic for several reasons.

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[100] TR at 772.

[101] TR at 947; A4NR OB at 23-24.

[102] TR at 947.

[103] A4NR-5

TTW was new and unique, and SCE had retained several expert consultants to assist SCE and MHI with analyzing the problem and providing possible restart options. Any repair options would take time to develop and implement. Moreover, the NRC had prohibited SCE from any restart until NRC certified SCE had complied with the many conditions of the March CAL. SCE implies that compliance with the CAL is pro forma and immediate. This is incorrect and SCE, an experienced operator, should have known better. As evidenced by how the NRC responded to SCE's eventual CAL response, submitted in October, there would likely be a six to eight month process lag until the NRC could issue written permission to start—assuming no license amendment was required (by no means assured).

During the first few months of 2012, SCE worked closely with the NRC, MHI, and its contracted experts Westinghouse, AREVA, and Intertek to investigate the damage and to develop operational assessments to support a limited restart of U2 for the purpose of testing impact on the SG tubes. SCE had near daily meetings with them and knew, or should have known, the general thinking and direction of the forthcoming AIT report and MHI RCA.

On May 7, SCE knew, or should have known, by its own analysis that U2 was susceptible to the same TTW, and could no longer be run at 100% power which provided the damaging steam flow. After months working with SCE on-site, MHI issued its RCA and AIT issued its Report in June, both of which reached conclusions about the presence and source of TTW consistent with SCE's own prior analysis. The AIT Report found that both the U2 and U3 SGs were susceptible to the design-induced TTW:

> "…the NRC team concluded that both units' steam generators were of similar design with similar thermal hydraulic conditions and

configurations. **Therefore, SONGS Unit 2 steam generators are also susceptible to this phenomenon (emphasis added).**"

Notwithstanding the potential for TTW, SCE teams worked with MHI and expert consultants to develop both a U2 restart plan, and long-term repair options for both units. SCE's restart plan was to operate U2 at 70% for five months then go offline to gather data about tube wear.

SCE contends the decision to restart U2 was part of normal operations for an operating generation facility--simply a delayed restart from a scheduled outage. It was more than that. SCE was prohibited under its license from restart of either unit, until it had completed a months-long response to the CAL, and the NRC had several more months to process the response. Yet, SCE did not consider other options, or consider that it had failed to accurately estimate the time necessary to obtain NRC approval. Instead, it was singularly focused on the restart option on the grounds that it "obviously" was the best option. As a consequence, SCE decided to retain the staff required for a fully operational facility, resulting in large O&M expenses even as some employees voluntarily left in September and later.

A decision-making process which does not consider alternative actions, cost effectiveness, or the ratepayer's perspective is not reasonable or prudent.

It is undisputed that the tube wear in U3 was more extensive than in U2 but the units have similar tube designs. In June, SCE began planning to put U3 into preservation mode, and the SCE Budget Review Committee met to defer capital projects. At that time, SCE knew U3 would not restart in the foreseeable future, and should have known that U2 was similarly situated.

U2 would not restart in 2012, in part because SCE was months away from submitting its CAL response, and six or more months away from NRC approval, assuming no license amendment would be required for the 70% test. This pushed the U2 restart date into at least 2Q 2013, but was not acted upon in contrast to SCE's actions regarding U3. For example, during a September Board of Directors meeting, SCE managers justified its move of U3 into preservation mode based on SCE's revised 4Q2013 estimate for U3 RTS.

The Commission finds the primary purpose of SCE's U2 restart plan was not for electric generation; it was a theoretical test for five months at 70% power, to gather data for long-term repair options. Therefore, it does not qualify as "normal operations" but as a strategic step towards long-term RTS in late 2013.

SCE did not establish that its decision to keep all systems operating instead of putting Unit 2 into preservation mode was reasonable. SCE acknowledged it would take just two months to move U3 from preservation mode to service-ready. Given the built-in time delays facing development and approval of SCE's restart plan, it is not reasonable to assume that U2 would restart in 2012, which might have justified retention of the employees. Instead, it was possible to decide that U2 could be handled similarly, even though SCE admitted it did not consider it. It may be that SCE's decision was reasonable when viewed in light of the lay-up and RTS costs, a consideration we will make during the entire SGRP review in Phase 3. However, we cannot find it reasonable in 2012 because it was ill-considered, based on the Phase 1 record.

Therefore, based on confirmation that U3 had tube-to-tube wear, the Commission finds that SCE knew or should have known by March 15 that a potential design defect was present in both units and thus fault could become an issue to rate recovery. Therefore, incremental SGIR costs would likely be disputed, and not suitable for immediate rate recovery until the Commission could develop a record about them.

The Commission also finds, based on confirmation that both units had tube-to-tube wear in the same area, that SCE knew or should have known by May 7, 2012 that pursuit of a restart plan for U2 was not in the interests of immediately restoring power generation for the benefit of ratepayers. Instead it was a brief theoretical exercise to further the development of long-term repair options with MHI.

The Commission concludes the record does not establish that costs associated with the restart and long-term repair options (SGIR) are routine O&M for which it would be just and reasonable to collect immediate recovery from ratepayers.

7. 2012 Recorded Expenses in SONGS Outage Memorandum Accounts

For 2012, SCE and SDG&E reported year-end recorded expenses to the Commission for their respective SONGSMA accounts, as follows (excluding power replacement and U2 RFO costs (discussed elsewhere in the decision):

2012 YE Recorded SONGS-related Non-capital Expenses ($000s)

Subaccount	SCE	SDG&E
Base -Routine O&M	300,489	72,685
Seismic Safety	3,261	832
Investigation	67,059	17,155
Repairs – After Outage	27,302	6,004
Regulatory – After Outage	3,421	903
Defueling	932	167
Litigation	6,145	--
Payroll Taxes	13,442	3,744
Other (Pensions, PBOP, Insurance)	23,059	31,624
Unit 2 Refueling Outage (RFO)	**35,255**	**9,116**
Total	**443,536**	**133,294**

8. Base O&M and Other Non-Capital Costs

In each utility's GRC, the O&M/overhead forecasts were based on normal operations at SONGS in 2012. However, SCE incurred routine operating expenses, as well as incremental other costs resulting from the outages of both U2 and U3 (SGIR). SCE and SDG&E also recorded other non-capital costs related to the U2 RFO and Commission-ordered seismic studies. (Capital expenditures are discussed below.)

8.1. Operations and Maintenance (O&M) Costs

In today's decision, we segregate recorded O&M costs into two categories: Base O&M and Steam Generator Inspection and Repair (SGIR) O&M. In the context of a GRC, Base O&M costs are primarily for labor and associated overhead costs. SCE submitted testimony which addressed SONGS total (100%) O&M by SONGS Functional Group.[104] SCE's testimony provided a description of the type of activities undertaken by each functional group, including some systems or activities SCE states are required by its operating license and associated technical specifications, to remain safely operable and capable of performing their design. Over the course of the proceeding, SCE eventually divided O&M into three categories: Base-Routine, Base-SGIR, and SGIR.

A summary of the type of activities and systems by functional group, preliminarily allowed (GRC) Base O&M costs, recorded costs, and an estimate of the percentage of costs necessary to comply with regulatory requirements as put forth by SCE is attached as Appendix D.

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[104] SCE-04.

SCE also provided a final 2012 O&M Summary by functional group which separates slightly revised costs by Base-Routine and SGIR-related costs.[105] Of the total $488,702 million recorded (100% $2012) for O&M costs, $347.747 million is recorded as Base-Routine, $140.955 million as SGIR-related (including Base-SGIR). This total amount is approximately $100 million more than the $389 million preliminarily allowed for all O&M in the GRC decision. In addition to Base and SGIR O&M, SCE also reports O&M costs related to information technology (IT), employee severance, and an artificial functional group for accounting purposes called Corporate Support. These costs are $9.054, $17.600, -$20.463 million, respectively. The negative value for Corporate Support reflects its use as a credit.

SDG&E 's O&M costs are not wholly derivative from its 20% ownership interest, because it applies separate overheads and calculates its own capital costs. For 2012, SDG&E reported total O&M as follows: $106.122 million for Base-Routine (+ overhead) and $26.34 million for SGIR-related.

8.2. Discussion of Base O&M and SGIR O&M

Typically, the Commission reviews forecasted costs in a GRC based on previous spending history and proposed new activities. The utility re-allocates the total revenue requirement adopted by the Commission based on emerging priorities. SCE contends that it did just that in 2012 with preliminarily allowed revenue --which SCE re-directed to inspections, testing, developing the U2 restart plan and long-term repair plans, and putting U3 into preservation mode.

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[105] SCE-35 at 6.

In this review, based on recorded costs, the Utilities' position is that all non-capital costs recorded in 2012 should be considered reasonable because as a prudent operator, SCE had a duty to identify the problems in the units, protect the assets for potential return-to-service, develop repair and return-to-service (RTS) plans, and to maintain safe operations and conditions at SONGS in compliance with regulatory requirements and SCE's NRC license and associated technical specifications.[106] Therefore, SCE and SDG&E assert the Commission should not order any refunds.

The Utilities rely on cost-of-service ratemaking principles where ratepayers are expected to pay for the reasonable costs of the generated electricity received, and utilities have an opportunity to earn a regulated rate of return over the estimated life of an asset. The Utilities reject the positions of WEM, CDSO, and WBA which advocate disallowance of all costs during these outages as a result of no electricity being generated. SCE argues it fundamentally undermines the risk sharing principles implicit in cost-of-service ratemaking, and further observes that ratepayers benefit when assets outlive expected service lives (e.g., hydroelectric plants).

The Commission agrees that cost-of-service ratemaking is applicable to regulated electric utilities, and automatic disallowance of all costs whenever there is an unplanned outage is erroneous. We expect that generation facilities like SONGS will have some planned and unplanned outages during ordinary operations. However, not all outages are the same, and indeed these extended outages resulting in premature, permanent shutdown are unique, particularly

[106] SCE-2 at 27.

after nearly a billion dollar investment, with generators in their first cycles of operation. The Commission has oversight responsibility to carefully examine an electric utility's actions to ensure that amounts charged to ratepayers are just and reasonable.[107]

All of the non-utility parties view SCE's testimony and other evidence as insufficient to establish what O&M costs SCE incurred and whether the costs were reasonable. There is some agreement that it may be reasonable for ratepayers to pay for "safety-related" costs, but no party accepted SCE's expressions of judgment as to the percentage of functional group expenses. DRA points out the offered percentages lack work papers or other supporting documentation.[108]

We have reviewed SCE's testimony and found the narrative descriptions similar to what is provided in a GRC, and consistent with the type of activities known to occur at SONGS. Although this review is based on actual costs, we agree with SCE that a sufficient showing does not require an itemized list of all O&M costs. Based on the Commission's knowledge gained through decades of regulatory oversight, we are able to find that SCE generally provided adequate explanations of what O&M activities it undertook and why, albeit without specific detail for Base O&M. (For the much more limited SGIR costs, SCE provided an itemized breakdown of costs.) In response to any residual concerns, we observe that SCE's books and records will be examined by ORA as part of its upcoming GRC, and the Commission always retains jurisdiction to audit.

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107 Pub. Util. Code § 451.

108 DRA-02 at 2.

For most Functional Groups, the recorded Base-Routine O&M is less than the GRC amounts, due in part to re-allocations of expenses to SGIR. One substantial example is the Engineering Group where SCE recorded more than $110 million to Engineering SGIR (discussed below).[109] Security costs also rose, but only about 5%., or $2.2 million, and are not unexpected.

Excluding Severance costs (discussed below), 49% of Base O&M costs are recorded in either the Maintenance or Nuclear Support Groups. SCE recorded $88.154 as Maintenance Base-Routine O&M, about $20 million less than the GRC amount.[110] SCE claims this is because it took steps to limit overtime and reduce contractor work force from about 200 to 65 full time equivalents, enhanced work processes, and rescheduled some non-critical maintenance activities.[111]

According to SCE, the Maintenance Group supports the actual plant electrical systems by "performing preventive and corrective maintenance and regular surveillance testing of mechanical and electrical equipment, instrumentation and controls, and protective devices" in compliance with various regulatory requirements, industry standards, and internal controls.[112]

The group reportedly processed 15,795 work orders during 2012, fewer than 4,000 were for U3. This low number is understandable given that (1) during April-May, SCE evaluated all scheduled preventive maintenance and surveillance testing resulting in suspension of 700 U3 work orders and re-

[109] SCE-35 at 6.

[110] *Ibid.*

[111] SCE-33.

[112] SCE-04 at 27.

scheduling 300 surveillance tests; and (2) in June SCE began planning to put U3 into preservation mode.[113]

The Nuclear Support Functional Group provides administrative support to SONGS O&M, including Business and Financial Services, Site Support Services, Nuclear Business Administration, and General Expenses. Activities include financial planning, budgeting, and accounting policies, preparation for ratemaking proceedings, record management, employee timekeeping, payroll, regulatory compliance programs, environmental protection programs, and payment of required fees.[114]

For the Nuclear Support Group, SCE recorded $82.5 million in Base-Routine O&M, about $7 million (8%) less than the GRC amount. SCE argues that regardless of whether SONGS is producing electricity, many of the identified functions of this group had to be carried out, particularly as it relates to the presence of employees, financial planning, and compliance with document-related regulatory compliance.

We observe that the activities described for both groups are generally of the type necessary to provide routine administrative services and to keep all systems operating, including critical systems necessary to keep the plant in a safe condition compliant with its operating license. That is to say – Base O&M. Similarly, we find that the activities described for the other Functional Groups are appropriate and predictable activities at an operating nuclear facility.

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[113] *Id.* at 28

[114] SCE-04 at 61-63.

Based on the historic O&M costs provided,[115] we find that the total recorded Base-Routine O&M is similar in proportion by Functional Group, and about 10.5% less in total amounts recorded, to what we would expect of an operating facility – the status the Utilities impute to SONGS.

However, we disagree that SONGS should be considered an "operating facility" for all of 2012. First, neither unit produced electricity for ratepayers after January 31, 2012. Second, by mid-March when it confirmed U3 TTW, SCE knew that there was a probability that issues of design fault would arise and SGIR expenses should be segregated for separate review. By May7, 2012, after confirming TTW and other types of tube wear in U2, SCE knew or should have known that it was not reasonably foreseeable that Unit 2 would return to producing electricity in 2012 or even that a short-term restart was viable.

Therefore, the Commission concludes it is reasonable for SCE to recover total recorded O&M, including Base-Routine and all SGIR (discussed in more detail below) for January, February, and half of March when all activities involved the reasonable response of a prudent operator to an unexplained outage. Beginning in the second half of March, all SGIR expenses, including Base-SGIR, are not yet eligible for rate recovery and shall be segregated for further review in Phase 3, subject to refund, where issues of outage-related fault or imprudence by SCE will be raised.

Additionally, SCE's Base-Routine O&M is reasonable through May. However, we find that SCE's request to recover all Base-Routine O&M recorded in 2012 is unreasonable. The record is not sufficiently detailed for the

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115 SCE-29 at Tab 8.

Commission to try to reconstruct what portion of post-May Base O&M is not reasonably associated with the minimum activities which would have been incurred if SCE had not pursued its decision to restart U2, and both units moved into preservation mode. We do know that SCE recorded normal time costs for SCE employees for SGIR activities as normal time funded via the base budgeting process. Therefore, commission finds recorded Base-Routine O&M is excessive after May.

Several parties criticize SCE's showing, and it is true that the Commission is not in a position to find that every O&M cost was properly recorded as "Base-Routine" O&M instead of SGIR. Nonetheless, such granular review is atypical for a GRC, and we note that in Phase 3 we will be examining SGIR activities more closely. Therefore, the Commission finds that ratepayers will be best served by proceeding with the record at hand to adjust rates with reasonable approximation.

In order to account for Base-Routine O&M costs incurred as a result of SCE's not well-considered decisions to maintain all, or nearly all, operating staff through the end of 2012, we conclude a gradually increasing reduction to Base-Routine O&M should occur, beginning in June. The Commission finds it reasonable and in the public interest to adopt a sliding path of decreasing Base-Routine O&M between June and December of 2012 to reflect both the unreasonable decision to devote all resources to a U2 restart in 2012, unrecorded credits, and various uncertainties about what was recorded in Base O&M.

Beginning in June, 10% of Base-Routine O&M shall be disallowed, followed by 20% in July and so on until November and December 2012 when

40% of Base-Routine O&M will remain in rates.[116] This amount approximately conforms with SCE's unsupported estimate that about one-third of SCE's Base-Routine O&M is necessary to maintain safe conditions and full regulatory compliance in a permanent shutdown mode. The result is reasonable because shutdown is a viable possibility for SCE after December 20, when MHI presents two repair options: SCE questions the viability of one strategy on a technical basis, and the other is full or partial replacement of the SGs, over a multi-year period.

The Commission finds reasonable and adopts the following 2012 Base-Routine O&M for SONGS-related costs, as follows (in 000s of 2012$, 100% share):

	Base - Routine	SGIR (includes both "Base" and "Total" SGIR)	Total
Recorded	347,746	140,956	488,702
Authorized	273,867	18,353	292,220
To Review in Phase 3	---	122,603	122,603

A worksheet for these calculations is attached as Appendix E.

8.3. Steam Generator Inspection and Repair (SGIR) Costs

SCE recorded $140.956 million (2012$, 100%) for 2012 incremental SGIR expenses, including $8.555 million re-allocated post-hearing from Base O&M.[117] Above, we found that $8.555 million recorded as SGIR through March 15, 2012

[116] In Phase 2 of these proceedings, the Commission is considering whether to remove plant from rate base, along with associated O&M, as of November 1, 2012.

[117] SCE-35 at 6.

was reasonable for ordinary operations during an unplanned outage. SDG&E's post-hearing adjustments identified $26.34 million recorded for incremental SGIR.[118] In support of these claimed amounts, SCE submitted testimony by Functional Group, as described above, including some descriptions of SGIR activities. SCE also provided an itemized breakdown by unit, work order, and Functional Group.[119]

SCE recorded about $113 million of SGIR costs in the Engineering Functional Group, more than 80% of total SGIR costs recorded in 2012. A majority of the costs ($94.6 million) was for outside consultants, experts, and contractors for testing, analysis, and tube plugging in both units.[120]

According to SCE, the Engineering group works in conjunction with Maintenance to perform day-to-day repairs of SONGS systems that remain in service. SCE also points to several regulatory-driven safety-related programs which SCE asserts must continue even during shutdown conditions.[121]

More specifically, the Engineering group consists of five functions: (1) Design Engineering; (2) Plant Engineering; (3) Nuclear Fuel Management; (4) Nuclear Safety Concerns; and (5) Nuclear Oversight and Assessment.[122] SGIR-Engineering costs are significant, states SCE, because the staff was fully engaged in plant restart activities (e.g., analyzing cause of tube wear in the SGs, defining and managing lay-up activities, determining repair options, supporting

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[118] SDGE-11 at 2.

[119] SCE-10 at 13 – 21.

[120] SCE-04 at 85-86.

[121] *Id.*at 35.

[122] *Id.* at 30.

regulatory review and requests for information, and maintaining the units available for restart).[123] This evidence is undisputed and, as described, corresponds to known emergent work otherwise documented in the record.

Some Engineering Expense was labor, "necessary to maintain qualified staff to perform functions required by the SONGS operating licenses and technical specifications."[124] No one challenged SCE's testimony that hiring and retaining qualified engineers is difficult, which made short-term staffing adjustments of engineers "cost-prohibitive and not the industry standard."[125]

The next largest recorded amount for SGIR was $7.4 million for the RadChemical Control Function (RadChem) Group, including $4 million for contractor health physics technicians and laundry services for radiologically controlled areas.[126] According to SCE, the Health Physics division establishes, implements, and manages the radiation protection and radioactive material control programs for SONGS, as well as interfaces with state and federal agencies responsible for radiological health and safety.[127] Its Chemistry division manages various chemistry control programs, manages the radioactive effluent monitoring program, and provides technical support.

During 2012, the Utilities argue that all of these activities are necessary to maintain SONGS in a safe and secure condition during extended outages, and to restore the units safely to service. The Chemistry division was particularly active

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[123] *Id.* at 36.

[124] *Ibid.*

[125] *Ibid.*

[126] SCE-04 at 86.

[127] *Id.* at 41.

in ensuring that U2's systems could be returned to service safely, and U3's systems were adequately protected for longer-term shut-down. Notably, SCE admits the total O&M (Base and SGIR) for this group would have declined overall if it had decided in 2012 to move for permanent shutdown.[128]

None of the non-utility parties support the Utilities' request for rate recovery of SGIR expenses in 2012. Instead, the parties outright reject all recovery because the facility was in extended shutdown, should have been permanently closed in 2012, costs should be paid by insurance and MHI, or SCE was at fault and its shareholders should cover the costs.

We give these arguments for automatic disallowance for all SGIR-related costs no weight because the record does not support them. We have made no finding that SCE was at fault or imprudently managed the steam generator replacement project, or unreasonably incurred the incremental SGIR costs in 2012. However, the prudence of SCE's management of the project, and whether costs associated with the replacement steam generators were reasonable and necessary, will form the basis for the third phase of these consolidated proceedings.

As we discussed in relation to Base O&M, an unplanned outage does not necessarily mean that a utility was at fault or that it should be assumed to be a permanent condition for purposes of rates. Moreover, SCE has agreed to apply any warranty or damage amounts from MHI, and insurance recovery, to offset SGIR costs for the benefit of ratepayers. SCE acknowledged it received a payment from MHI for $45.5 million (100%) and it should be applied towards

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[128] *Id.* at 44.

SGIR costs as determined in Phase 3. However, we decline to speculate as to future third party recovery and prematurely apply credits before funds are in hand.

Our review of the (100%) costs allocated to SGIR is incomplete. Based on the itemized SGIR costs initially provided by SCE, the Commission makes an initial finding that the items and activities referenced appear to be of the sort that could be undertaken to investigate, inspect, and repair steam generators, develop and implement a restart plan, and move a reactor unit into preservation mode.

However, we have not yet determined whether these costs are reasonable under the circumstances and, therefore, whether ratepayers should pay for any of them. In Phase 3, we will examine the 2012 incremental costs in context of the overall SGRP and SCE's management of the project, and apply third party payments received from MHI or insurance.

Above we concluded SCE was reasonably pursuing normal operations, or a return thereto, through May 2012. During June through December, we made reductions to recorded Base O&M given SCE's decision to restart and maintain full operations at SONGS throughout 2012. The result is that the removed Base O&M is re-allocated to SGIR for final review in Phase 3.

Therefore, the total 2012 SGIR expenses, subject to further review in Phase 3 is $122,603 million.

8.4. Severance Pay

In its 2012 GRC, SCE forecast preliminary workforce reductions of 500 SONGS personnel, and 100 contractors, to align the workforce with those of the other nuclear generating sites over time.[129] The Commission found the proposed reductions had been delayed since 2009, resulting in ratepayers funding excess positions for two years to rectify management problems at SONGS which required a resetting of the safety culture through various activities. We determined that SCE should allocate to ratepayers 100% of savings from reductions of SONGS personnel.[130]

Based on the changed conditions and 2012 staffing needs, SCE revised planned reductions to 730 over 2012-2013, reducing staff by almost one-third, from 2,250 to 1,500.[131] SCE reports voluntary severance of 258 employees and involuntary severance of 15 managers, in November and December of 2012. The actual severance costs were $17.6 million, with savings of $3.96 million.[132]

The GRC O&M amounts included all estimated severance costs within Functional Groups.[133] In SCE's report on recorded O&M, severance costs are a presented as a separate item, and not available by Functional Group. SCE stated the delayed reductions were a result of re-allocation of staffing to meet new inspection and repair activities, the need to retain highly skilled employees for anticipated outage and restart-related tasks, and the lengthy process to layoff represented employees, e.g. collective bargaining, bumping rights.[134]

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[129] SCE-1 at 2.

[130] D.12-11-051 at 33; (TR at 1211 SCE witness Mr. Worden stated that the GRC model had not made that adjustment, but SCE would abide by it if adopted here).

[131] SCE-04 at 36.

[132] *Ibid.*

[133] TR at 369.

[134] TR at 1089-90.

Although employee severance costs are routine costs, the Commission finds it was not reasonable for SCE to retain full staffing through November of 2012. The Commission also finds that SCE has not credited the $3.96 million in 2012 savings from staff reductions to the overall calculation of costs. In order for rates to be just and reasonable, we conclude that this credit must be made to the overall costs subject to rate recovery for 2012 Base O&M. We address both issues as a part of the gradual O&M reductions adopted above.

8.5. Seismic Studies

In D.12-05-004, we approved SCE's and SDG&E's applications to record and recover their actual costs of up to $64 million (nominal $, 100% share) in O&M costs associated with seismic studies at SONGS. These studies are responsive to Public Resources Code Section 25303 and recommendations of the California Energy Commission.[135] In testimony, TURN suggests that these seismic study costs are related to relicensing and should be disallowed,[136] but does not advance this argument in briefs. In testimony and briefs, SCE suggests that TURN misunderstands the purpose of the seismic studies and asserts that the studies are a regulatory obligation, not related to license renewal.[137]

SCE's recorded costs for seismic studies in 2012 are $3.261 million; SDG&E's are $815.5 thousand.[138]

We find that these studies were authorized by this Commission and are not directly related to the operational status or relicensing of SONGS.

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135 D.12-05-004 at 1-2.

136 TURN-1 at 9.

137 SCE OB at 24-25, citing SCE-8 at 9.

138 SCE February 1, 2013 Monthly Report in Compliance with I.12-10-013; SDGE-11 at 2.

D.12-05-004 describes certain ratemaking treatment for these studies. Based on the record in this proceeding, we do not make any changes to the previously approved ratemaking treatment of these studies.

9. 2012 Capital Expenditures

SCE initially planned to undertake substantial capital projects at SONGS during this rate cycle. In the 2012 GRC decision, the Commission preliminarily authorized SCE to expend $189.2 million ($2012, 100%) for anticipated operational needs.[139] SCE actually recorded $167.6 million (100%) in total capital expenditures. Unlike O&M expenses, SCE's testimony combines U2 RFO capital expenditures and SGIR expenditures with all other SONGS-related capital expenditures.

9.1. Utility Applications

SCE asks the Commission to find that its 2012 SONGS-related capital expenditures of $131.08 million (SCE share) are reasonable, along with other capital costs recorded in SONGSMA. SDG&E requested approval for $49.3 million in capital expenses, comprised of $39.25 million identified as its 20% share of SONGS capital expenditures billed by SCE, adjusted for overheads ($1.19 million), plus $8.82 million for AFUDC.[140] (It is unexplained whether the AFUDC is actually attached to plant into rate base during 2012.) SDG&E's testimony also addresses its capital-related revenue requirement—a different calculation and rate component.

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[139] SCE-04 at 88.

[140] SDG&E-3 at 9; See Appendix B (SDG&E's reports capital expenditures of $38.475 million in its SONGSMA).

According to SCE, Units 2 and 3 required on-going capital investment in 2012 to maintain the plant's condition at a level supporting long-term safe, regulatory-compliant, and reliable operation – both in the near-term during shut-down conditions and in the long-term when and if either or both return to service. SCE provided cost and descriptive information about the capital projects (most presented earlier in the 2012 GRC), and took steps to postpone, suspend, or cancel some projects during 2012 based on the extended outages, including projects related to the suspended U3 refueling outage.

SCE contends that recorded capital expenditures are $21.6 million less than preliminarily allowed, largely due to the outages. Implementation of SCE's plan to postpone, cancel or re-schedule capital projects during 2012, claims SCE, also led to savings. Therefore, SCE asserts that all expenditures should be found reasonable.

SCE points out that 47% of the capital expenditures were incurred prior to April 2012 (with the majority of that amount incurred during the Unit 2 Cycle 17 RFO), before the full extent of the wear conditions of the Unit 2 & 3 steam generators was known. SDG&E supports SCE's position that over 80% of the 2012 capital expenditures were necessary to maintain the units in a safe and secure condition, or to meet federal and state regulatory requirements.

SDG&E provided a table of adjustments to SCE invoices for its pro rata share of capital expenditures. SCE provided a narrative description of capital projects SCE states it was unable to defer, such as the U2 RFO, as well as those it could postpone or suspend without compromising safety. SCE classifies the capital projects under the following sub-categories:

Capital Expenditures By Category[141]
($2012, $millions)

Category	Projects	100%	SCE	SDG&E
Common Required includes capital projects for site, not unit specific, but necessary;	more than $23 million is required for storage of spent fuel	38.389	30.024	7.678
Work In Progress Projects in progress in 2011, mostly completed, required to sustain plant infrastructure	Completion prudent given mostly complete; includes back-up generators; almost 90% is related to U2 RFO;	84.533	66.113	16.907
Emergent-Regulatory Required not forecast, due to new regulatory requirements	74% for various security projects; $2.6 million for	17.937	14.029	3.587
Rescheduled Projects begun in 2012 & suspended due to outages	Small U2 and U3 projects	1.434	1.122	0.287
On-going Completion Rescheduled Projects started before 2012 suspended due to outages	Primarily for U3 RFO, $9 million for high pressure turbine	19.754	15.450	3.951
Marine Mitigation Requirement of Coastal Commission permit	$4.2 million for corrective construction to wetlands project; monitoring of artificial reef	5.559	4.350	1.112
Total (includes RFO)		$167.61	$131.088	$33.522

DRA and WBA argue that the Commission should not find any SONGS-related capital expenditures to be reasonable. DRA contends the Utilities did not provide sufficient information to establish reasonable capital

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141 *Id.* at 89-113; Appendices A and B to this Decision (Year End 2012 SONGSMA report).

expenditures in 2012. Both DRA and WBA ask the Commission to further defer review of these expenditures.[142] However, we find deferral unnecessary because there is sufficient evidence to make an approximate determination of reasonable capital expenditures during 2012.

We agree with the Utilities that some capital expenditures were necessary during 2012, even though the reactor units were not operating, because the NRC operating license requires SCE to maintain many systems in order to protect the safety of the plant, its workers and the public

Our review of the pattern of expenditures confirms that more than $89 million (53.5%) of total capital expenditures were booked between January and April 2012, primarily for the U2 RFO. We conclude below that the RFO was essentially completed before SCE had knowledge of the extent and nature of tube wear in U2, and allow O&M associated with the RFO as reasonable. Similarly, we find that SCE's capital expenditures for the U2 RFO were reasonable when made, although we do not concur that SCE established the U2 RFO expenditures are necessary for maintaining a safe plant during the outage.

On the other hand, we found elsewhere in this decision that SCE knew or should have known by May 7, 2012 that it was not reasonable to expect either unit to return to service for up to a year. Therefore, we find that SCE 's effort to suspend, cancel, and re-schedule some projects, while commendable, was inadequate to reflect the overall reduction of capital projects that should have occurred at SONGS.

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142 DRA OB at 12.

It is appropriate to reduce the amount of 2012 SONGS capital expenditures the Commission finds reasonable by 20% to reflect what the Utilities' internal experts determined were not necessary to safely maintain SONGS during the 2012 outage, in compliance with applicable federal and state regulations.

Therefore, the Commission finds that only $134.08 million (80%) of 2012 total recorded capital expenditures ($167.6 million) are reasonable. Capital expenditures will be subject to further review in Phase 3 if the expenditures were made as a result of the tube damage in the U2 and U3 SGs.

9.2. Capital-related Expenses Derived From Rate Base

When capital projects are completed, the capital expenditures are recorded into rate base as in-service and capital-related expenses (e.g., depreciation, taxes, return) are charged to ratepayers. According to SCE's SONGSMA report, the capital related-expenses increased substantially beginning in March and more than half of the total revenue requirement for these expenses was added between March and May 2012.

Although SCE provided assumed closing dates for its 2012 capital expenditures, SCE did not identify which capital expenditures and projects were actually moved into rate base during 2012. In the SONGSMA, SCE reported its net rate base (additions and removals) grew by $78.66 million from January 30, 2012 through December 31, 2012.

Additionally, 2012 combined capital-related revenue requirements exceed preliminary allowed amounts for both utilities. For example, SCE recorded depreciation expenses of $80.3 million, or $20.3 million more than the GRC amount.143 Tax expense also exceeds the GRC amount by $18.4 million. SDG&E similarly asks that its capital –related revenue requirement be found reasonable, but did not support its request for recovery of $27.3 million, $3.1 million more than its GRC estimate.

TURN and DRA are the only parties to directly address capital-related expense. DRA argues that utility recovery of SONGS Units 2 and 3 rate base related revenue requirements, along with SGRP revenue requirements, should be terminated effective January 31, 2012, the date of the Unit 3 forced outage. The SGRP revenue requirement is not at issue in this phase. However, we agree that not all capital investment moved into rate base was reasonable, as evidenced by excess capital-related expenses charged to ratepayers, and the net increase to rate base over the year.

However, DRA's recommendation to remove all SONGS assets from rate base is too blunt because it does not consider that capital work at U2 was part of a scheduled outage, that SCE did not know as of January 31, 2012 that U2 and U3 were not likely to return to service in 2012, or thereafter what capital was reasonable and necessary to maintain safe and secure conditions at SONGS in compliance with federal and state regulations.

TURN's position is that, as of November 1, 2012, the capital-related costs of U3 should be removed from rates based on the principle that fixed costs should be removed from base rates if there is no near-term timetable for a unit to come back. The single largest capital cost is the return, taxes, depreciation, and property tax for U3 (excluding common plant), which has about $110 million of

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[143] SCE SONGSMA Report (February 1, 2013 at 3).

rate base (return plus income taxes) plus property taxes in the range of $14.5 million annually, and depreciation expense of approximately $25 million. TURN's position is based on § 455.5 which will be addressed by the Commission in Phase 2.

The Commission finds that SCE's recorded rate base is excessive and should be reduced to reflect the changed conditions at the plant as the year progressed. The reduction should reflect removal of capital projects added to rate base in 2012 that do not compromise the safe operation of the plant in compliance with all regulatory requirements during the year. Therefore, it is reasonable to apply the 20% reduction adopted for capital expenditures to serve as a reasonable proxy for excess capital projects moved to rate base in 2012. This amount shall be removed from the rate base and any associated revenue requirement found to be unreasonable for 2012.[144]

There is no need for SCE to attempt, post-decision, to try to parse its capital projects in a different way. This decision only affects 2012 revenue requirement. Evidentiary hearings in Phase 2 have already been held where the Commission will address all SONGS plant in rate base and associated O&M pursuant to § 455.5. Furthermore, all costs related to the SGRP and subsequent outages remain under review in Phase 3 where issues of fault could lead to further rate reductions.

TURN also proposed that 50% of the Materials & Supplies (M&S) inventory be removed from rate base. However, SCE opposes the adjustment on

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[144] Due to tax consequences, the reduction in rate base actually results in an increase to revenue requirement of $0.5 million; larger reductions to rate base would result in a higher revenue requirement.

two grounds: (1) it was reasonable to maintain M&S inventory in 2012; and (2) TURN assumes an erroneous premise that M&S is apportioned 50/50 by unit. TURN's assumption is incorrect, and fails to recognize that some M&S is for common plant.

TURN's position is predicated on a finding that U3 should be removed from rate base in Phase 1 because it is abandoned plant. The Commission has not made that finding and the Phase 1 record does not support that result. We also observe that it would result in nominal increase to revenue requirement.

No other specific testimony or argument was made by a party about these elements of revenue requirement. As described above, the Commission previously authorized rate recovery of SGRP costs until the post-completion reasonableness review occurs. We view TURN's requests to reduce rate base as relevant to the Commission review of rate base pursuant to § 455.5 in Phase 2.

9.3. Construction Work in Progress

During 2012 a number of capital projects at SONGS were delayed or suspended. By the end of the year, SCE recorded $216.7 million (SCE share) for Construction Work in Progress (CWIP).[145] CWIP costs are not in rate base. This amount reflects projects where money has been spent but the project was not yet in-service at the end of 2012. Allowance for Funds Used During Construction (AFUDC) represents the cost of financing capital projects before they enter service. It is accumulated while the projects are under construction, and then included with the capital cost of the project when added to rate base.

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[145] Appendix A.

The associated AFUDC accrued by SCE for these capital projects totaled $14.5 million.[146] SDG&E reports that, at as of December 31, 2012, it had recorded $110.855 million in CWIP, but did not identify accrued AFUDC.[147]

TURN initially recommended the Commission order SCE to stop accruing AFUDC on suspended capital projects, retroactive to the date of suspension.[148] As a result of SCE's 2013 decision to permanently shut down the entire facility, TURN urged the Commission to presume all recorded CWIP represents abandoned plant as of December 31, 2012, ineligible for the accrual of AFUDC. The requested result would be that the Utilities zero out all accrued AFUDC.[149]

TURN primarily relied on accounting standards to support its view. TURN cites Statement of Financial Accounting Standards (SFAS) No. 34 which requires the capitalization of interest to cease when a construction project is suspended voluntarily by the company. Federal Energy Regulatory Commission (FERC) requirements are apparently similar as applied to suspended construction of gas pipelines.

SCE and SDG&E adamantly opposed TURN's recommendations. They object that, if adopted, the Commission would be improperly preventing the utilities from recovering the 2012 cost of financing SONGS capital projects, regardless of future events.[150] During 2012, it was not clear whether U2 or U3

[146] TURN OB at 9-10.

[147] Appendix B.

[148] TURN-1 at 10.

[149] TURN OB at 3-4.

[150] SCE-8 at 10.

would return to service, but the capital expenditures had received preliminary approval.

SCE also argues that the referenced accounting standards are neither determinative, nor applicable. We agree with SCE that the Commission's judgment on whether costs are reasonable is not controlled by accounting standards. The utilities distinguished the accounting rules cited by TURN. TURN did not refute SCE's claim that SFAS-71, not SFAS-34, is the applicable accounting rule for public utilities, and provides for accrual of financing costs with capitalized costs.[151]

We also disagree with TURN's premise that since the June 2013 announcement that SONGS will not restart, it is reasonable to assume the plant will be removed from rate base, the CWIP will never be placed into rate base, and there is" no possibility that these capital projects will be deemed used and useful."

This phase is primarily an extension of the 2012 GRC, converted from a forecasting exercise to review of what was reasonable given what SCE knew at the time it incurred the expenses. The Utilities state that, in 2012, SCE did not suspend substantially all activities at SONGS, and some necessary capital work continues.

We agree it is not reasonable to impute knowledge of a June 2013 decision to shut down SONGS permanently, to SCE during 2012. Furthermore, TURN jumps to the conclusion that no 2012 capital projects could be reasonable, an assumption that seems imprudent given that some critical systems may be

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[151] SCE-8 at 10; SDG&E-5 at2.

impacted and capital investment required to meet regulatory obligations regardless of the operating status of the plant in 2012. Thus, some projects recorded in CWIP may have entered service in 2012, or will enter service in the future.

TURN suggested an exception to its blanket disallowance of all CWIP for capital projects which SCE can show are necessary to maintain safety at the facility under permanent shutdown.[152] However, this neither addresses the fact there is no evidence to show that SCE knew in 2012 that it would permanently shut down SONGS in 2013, nor that projects to maintain safety adequately describes the universe of reasonable capital projects left at SONGS.

Therefore, the Commission does not find it reasonable to prevent the Utilities from accruing AFUDC in 2012 for SONGS-related CWIP. However, the issue is relevant in phase 2 where the Commission may remove some SONGS plant from rate base, and associated projects may become permanently abandoned.

9.4. Cash Working Capital

SCE did not calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012. CWC is a component of rate base which represents the shareholder cost of funding day-to-day operational requirements when there is a gap between the time expenses must be paid and corresponding revenues must be collected. The Operational Cash requirement is the average balance of funds SCE's investors provide the utility to meet its daily operational needs.

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[152] TURN OB at 3.

In SCE's 2012 GRC, SCE provided a "lead lag" study to determine the required funds, based on estimated timing differences between when certain operating expenses are paid and revenues are received.[153] The Commission adopted SCE's Revenue Lead lag study, but made several adjustments advocated by DRA and TURN to SCE's proposed Expense Lag Study.[154] To the extent the Commission decides to make changes to revenue requirements in this proceeding, there will be some minor consequential effects to CWC.

TURN initially called for a SONG-specific lead lag study to support a SONGS-only CWC calculation, claiming that some SONGS costs would otherwise be omitted from review. At the evidentiary hearings, TURN's witness acknowledged that such a study could require significant extra work, and agreed that use of the company-wide lead lag study to SONGS expenditures would still be useful.[155]

In its post-hearing brief, TURN clarified that it wanted the Commission to order SCE to calculate a SONGS-only cash working capital (CWC) calculation, separate from its overall utility-wide CWC, using the parameters adopted in the 2012 GRC.[156] SCE disputes this approach, because the total company-wide Expense lag does not necessarily reflect the Expense Lag associated with SONGS.[157]

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153 D.12-11-051 at 633-34.

154 D.12-11-051 at 640-645.

155 TR 795-896.

156 TURN OB at 4.

157 SCE OB at 45; SCE-8 at 3.

We agree with TURN's intent to capture all 2012 SONGS-related costs for review in this Phase. SCE stated in its post-hearing brief that if it were directed to perform the calculation, it could develop an approximate estimate using the lead-lag days adopted in the GRC. Although not a perfect measure, the Commission finds it reasonable to direct SCE to perform the calculation, as it proposed, which may result in a minor, but reasonably appropriate, adjustment to SONGS rate base. SCE shall provide the Commission with this calculation as part of the revised modeling of the revenue requirement which SCE shall undertake as a result of this decision.

10. SDG&E Other SONGS-Related Costs

SDG&E incurred $60.492 million of SONGS-related costs not included in the SONGS portion of SCE's 2012 GRC or in SCE's OII testimony.[158] These cost categories and forecast amounts were addressed in SDG&E's 2012 GRC and include capital-related expenses arising from the SGRP.

SDG&E's SONGS-Related Costs Deferred from GRC
($YOE 000s)

Category	Amount
SONGS Unit 1 Spent Fuel Storage	994
SONGS Site Easement	20
SONGS Insurance	2,364
SONGS Operations and Billing Oversight	642
SONGS Depreciation	23,273
SONGS Taxes	13,270
SONGS Return on Rate Base	19,929
Total	$60,492

158 SDG&E-3 at 2.

SDG&E provided testimony which described the nature of these expenses, although somehow omitted any reference to the SGRP. The categories Depreciation, Taxes, and Return on rate base include a total of $29.1 million related to the SGRP. We expect this omission was an oversight and not intended to shield this component from review SDG&E argues that all of these costs are required regardless of whether SONGS is operating and have been deemed reasonable in prior rate cases. SDG&E requests the Commission find the expenses reasonable and prudent.

We recognize that, under a prior decision, the Utilities currently have authority to recover these costs. However, SDG&E is aware the decision also provided for a final reasonableness review of the SGRP costs, which will occur in Phase 3 of these proceedings. Therefore, our interim finding that these costs are reasonable does not exempt these SGRP costs from the final review to come.

With that caveat, the Commission finds these 2012 costs to be reasonable and authorizes rate recovery.

11. Community Outreach and Education

At the request of Joint Parties and others, the Commission included in Phase 1, a review of SCE's 2012 actions and expenditures for community outreach and emergency preparedness related to the SONGS outages. The costs of SCE's Customer Outreach and Emergency preparedness programs are part of the company-wide GRC review, primarily through budgets for Local Public Affairs and Corporate Communications. SCE 's community outreach program is implemented in three public zones: a 10-mile radius from SONGS is the

Emergency Planning Zone, a 20-mile radius is the public education zone, and 30-50 miles is the "ingestion pathway" zone.[159]

SCE points out that the requirements for emergency preparedness followed by SCE, and other operators of commercial nuclear plants in the United States, are established by the NRC, Federal Emergency Management Agency (FEMA), and certain state agencies. SCE described its emergency preparedness activities on an on-going basis, and illustrated what it called "a significant community presence in the region surrounding SONGS."

For example, SCE performs regular drills and exercises site-wide and in coordination with the Interjurisdictional Planning Committee (IPC). In 2012, SCE reports it also provided radiological training for area Emergency Responders and updated service agreements with several area hospitals and transportation services.

After the outages, SCE states it also stepped up its public education program within the 20-mile plant radius, including numerous outreach presentations to local communities and school districts, sent Emergency preparedness brochures to 60,000 ratepayers within the federally-established 10-mile Emergency preparedness Zone, and expanded availability of Spanish language materials within the 20-mile public education zone.

Both Joint Parties and WEM ask the Commission to order SCE to segregate SONGS-related public education activities from SCE's company-wide program and subject these costs to future review. Both parties contend that SCE's efforts are insufficient, and include significant corporate image activities of questionable

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[159] "Ingestion pathway" refers to the potential for radiation to contaminate food sources.

value to the ratepayers. WEM criticizes the content of SCE's materials as "pro-nuclear public relations." WEM suggests a broad range of potential consequences of radiological leaks and emergency instructions should be required, and more extensive outreach beyond regulatory requirements. Joint Parties want the Commission to order SCE to appoint a single person to coordinate SONGS-related outreach and emergency preparedness and to translate all materials into numerous languages.

SCE observes that WEM does not dispute that SCE remains in full compliance with state and federal regulatory requirements, nor does WEM argue that SCE has failed to comply with any federal, state, or county regulations regarding emergency preparedness. No party contradicted SCE's assertion that, to the extent WEM objected to certain statements in its materials, the statements are accurate and consistent with similar information disseminated by federal and state authorities responsible for emergency preparedness in the event of a nuclear power plant accident.

SCE also provided evidence that, in 2011, the NRC reaffirmed its commitment to the 10-mile radius requirement for Emergency Planning Zones (EPZ) around U.S. nuclear power plants. The NRC said, "The current EPZ size has been in use since the 1970s and was the result of extensive emergency planning studies performed by a federal task force. That task force concluded a 10-mile-radius EPZ would assure that 'prompt and effective actions can be taken to protect the public in the event of an accident' at a plant."

SDG&E adds that the Commission has already rejected Joint Parties' proposal in the SDG&E 2012 GRC. In D.13-05-010, the Commission said, "to impose a SONGS-related community outreach program on SDG&E would be duplicative of what SCE already does, and would result in unnecessary programs whose costs would be borne by ratepayers."

We are not persuaded that SCE's SONGS-related outreach fails to meet regulatory requirements or misleads the public. The Emergency Planning zones are established by the federal government, and there is insufficient evidence in the record for the Commission to intervene in the multi-jurisidictional emergency planning in place. Although some community outreach activities listed by SCE may have a self-serving component in terms of corporate image, we have previously supported an IOU's involvement with communities within its service territory.

On the other hand, we agree with the thrust of parties' concerns that, going forward, communities surrounding SONGS will begin to learn more about the coming decommissioning and have new questions and concerns. Therefore, the Commission finds it is in the public interest for SCE to expand its public education about SONGS and the future decommissioning beyond the 20-mile designated public education zone to 50 miles for the immediate future. SCE shall be particularly sensitive to pockets of alternative language users and coordinate with community based organizations to ensure wide distribution of public information and availability of emergency planning information.

Therefore, within 90 days of the effective date of the decision, SCE shall make an Information-only Filing, as defined in Section 3.9 of the General Rules of General Order 96-B, to the Commission which identifies SCE's strategy for expanding its public outreach activities as described.

12. Refueling Outage (RFO)

In SCE's 2012 GRC A.10-11-015, the company requested approval for two refueling outages (RFO) in 2012, one for SONGS Unit 2 during January –March

2012 and one for Unit 3 during October – December 2012, at a cost of $46 million (100%) each, or $36 million (SCE share). SCE submitted that it began the first RFO in January 2012 on U2. However, in the decision for SCE's 2012 GRC D.12-11-051, the Commission noted that U2 was not restarted and directed SCE to track the RFO expenses in the SONGSMA for future reasonableness review.[160] Based on the operational uncertainty of the SONGS units, the Commission continued the flexible outage schedule mechanism for the GRC cycle, but did not allow preliminary recovery of SCE's estimate of $72 million (SCE share) for the two forecast RFOs in 2012.[161]

12.1. Parties' Positions

SCE notes that based on its 2011 expectations, "the company included expenses for two RFOs – totaling $102.606 million – in rates." However, since D.12-11-051 did not authorize any 2012 revenue requirement for RFOs, SCE has "overcollected" by that amount. SCE explains that, "through the routine operation of SCE's Base Revenue Requirement Balancing Account (BRRBA)" the difference will be refunded to ratepayers, through SCE's 2013 ERRA forecast proceeding.[162]

During January – March 2012, SCE conducted one RFO, the U2 Cycle 17 RFO, at a cost of $45.1 million; the U3 Cycle 17 RFO was not conducted.[163] SCE's testimony describes the activities of the U2 Cycle 17 RFO.[164] SCE asserts that

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160 D.12-11-051 at 34.

161 *Ibid.*

162 SCE Phase 1 OB at 46-47, citing SCE0-7 at.6.

163 SCE Phase 1 OB at 46, citing SCE-4 at 76.

164 See SCE-4 at 69-76.

these activities were "incurred before SCE was aware of the extent of the tube wear in either unit" and that the Commission should, in this proceeding, find the costs reasonable and authorize SCE to recover them in rates.[165] SCE summarizes this ratemaking in its testimony:

> In other words, SCE will refund the previously-collected forecasted costs of the Unit 2 and Unit 3 Cycle 17 RFOs when the recorded 2012 BRRBA balance is included in rates, and is seeking to recover the recorded costs for that Unit 2 Cycle 17 RFO costs in future rates.[166]

SDG&E notes that its 20% share of RFO costs were invoiced by SCE and paid by SDG&E. SDG&E asserts that these costs are reasonable and should be recovered in rates.[167] SDG&E further explains that it included $28.7 million in 2012 rates for two RFOs (via Advice Letter 2302-E), and that it has already (via Advice Letter 2416-E) refunded, in 2013 rates, the amount not spent on the 2012 RFO.[168] SDG&E does not clarify in testimony the amount it recorded for the U2 Cycle 17 RFO. In combination SDG&E's Quarterly Reports on its SONGS Outage Memorandum Account dated June 10, 2013 and July 1, 2013[169] show a recorded cost of $9.1 million for the 2012 RFO.

DRA "recommends that the Commission direct SCE to refund any RFO revenues recovered in rates that are in excess of the RFO expenses incurred in 2012 and incorporate the adjustment in rates immediately."[170]. DRA's calculation

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[165] SCE OB at 47.

[166] SCE-7 at 7.

[167] SDG&E Phase 1 OB at 4.

[168] SDGE-6 at 1-3.

[169] Line 29: "Refueling {1 in 2012}."

[170] DRA Phase 1 OB at 15.

of the over-collection is that $102.6 million was authorized for two RFOs in 2012,[171] and the actual costs of the U2 Cycle 17 RFO were $45.1 million,[172] yielding a difference of $57.5 million to be refunded.[173]

TURN suggests that SCE made an unreasonable decision to place new fuel in the U2 core during the RFO and the consequence "was an unnecessary destruction in value that could have been recouped through a resale of the unused fuel."[174] TURN asserts that SCE-4[175] demonstrates that by "early February of 2012" SCE had "substantial evidence of problems" at U2 prior to moving the fuel to the core, completed on March 1.[176] TURN-1 shows that SCE transferred $121 million to the in-core inventory in June 2012.[177] TURN suggests that the Commission can calculate lost value "either by relying on an independent assessment or by using pricing data when SCE ultimately sells its existing unused pre-core fuel inventory."[178] CDSO also argues that moving fuel to the U2 core was unreasonable.[179] CDSO observes that SCE witness Palmisano estimates a typical timeframe for moving fuel to the core is seven days.[180] SCE

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171 DRA-1 at 10.

172 SCE-4 at 76.

173 DRA Phase 1 OB at 15.

174 TURN Phase 1 OB at 10.

175 At 77.

176 TURN Phase 1 OB at 10, citing timeline in SCE-10, Question 4 at 1.

177 TURN-1 at 3.

178 TURN Phase 1 OB at 11.

179 CDSO Phase 1 OB at 4.

180 *Id.* at 5, citing RT 764:16-18.

concurs with this observation, and places the start date at approximately February 25.[181]

SCE contends that TURN and CDSO's claims "assume perfect foresight regarding the nature and extent of the Unit 3 steam generator failure, which was not understood until a later point in time."[182] SCE's Palmisano interpreted the U2 testing, as of February, 2012, to show "overall satisfactory results."[183] Because contractors were already on site, SCE further argues, delaying insertion of the fuel as scheduled would have imprudently resulted in additional costs.[184]

WEM, A4NR, and Joint Parties do not directly comment on the subject of RFO costs.

12.2. Discussion

No party contests that exactly one RFO occurred in 2012, and no party has challenged the amount recorded by the utilities for the U2 Cycle 17 RFO. We agree with DRA's recommendation that any over-collection for a second 2012 RFO originally forecast for U3 should be refunded, to the extent that that refund has not already occurred. We find that SCE's cost of $45.1 million (100% share) for the 2012 U2 Cycle 17 RFO were reasonably incurred and authorize each utility to recover their share of these costs in rates. Any amount previously collected beyond this amount, including any collection for the U3 Cycle 17 RFO that did not occur, shall be refunded to ratepayers, to the extent that such a refund has not previously occurred.

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181 SCE Phase 1 Reply Brief (RB) at 3.

182 SCE Phase 1 RB at 3.

183 RT 850:11-14.

184 SCE Phase 1 Reply Brief at 3, citing RT 766:13-24.

Despite arguments by TURN and CDSO we find that SCE's decision to place new fuel in the U2 core was reasonable. Before SCE initiated the fuel insertion on February 25, 2012, SCE did not have sufficient evidence to delay placing fuel in the reactor of U2. Although SCE knew of the U3 steam generator leak and of unexpected levels of tube-retainer bar wear in both U2 RSGs, it did not yet know of TTW in one of the U2 RSGs. SCE testimony, cited by TURN,[185] does reference TTW, but TURN mistakenly attributes this conclusion to the U2 "expanded" eddy current testing completed on February 14, 2012. The correct date of this finding is April 10, 2012,[186] which apparently corresponds to the "special interest" eddy current testing started on April 5, 2012.[187]

13. 2012 Replacement Power Cost Calculation (Phase 1A)

The purpose of Phase 1A of this proceeding is to adopt a method for calculating the approximate[188] cost of replacement energy and capacity, foregone sales, and other market related costs (collectively "replacement power costs") of the outage of SONGS. If, in a later phase (tentatively Phase 3) of this proceeding the Commission determines a certain range of dates that SCE and SDG&E should not be allowed to recover the replacement power costs, this method will be

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185 SCE-4 at 77 and SCE-10, Question 4 at 1.

186 RT 852:21-25.

187 SCE-10, Question 4 at 1.

188 We cannot calculate the precise replacement power costs because market participants, including the utilities, would have made different bidding, procurement, and operational decisions if the outage had not occurred. Consequently, it is impossible to know with certainty the outcome of those decisions or the market prices that would have resulted. See SCE-2 at 19. No party suggests that it is possible to calculate replacement power costs exactly.

applied to calculate replacement power costs for those dates. As scoped, Phase 1A is limited to calendar year 2012. However, if circumstances require, we will investigate what, if any, differences in the method should be used for other time periods. We reiterate that the costs referenced here are only for meeting the needs of bundled customers; this discussion is separate from ongoing discussions in the long term procurement plan proceeding, Rulemaking 12-03-014, about system reliability in light of the SONGS outage and retirement. Here we focus exclusively on the cost of what has been done to meet the needs of bundled customers in 2012, not what may (or should) be done in the future on behalf of system customers.

13.1. Definition of Replacement Power

Some of the parties have devoted considerable energy to the debate of what categories of costs should actually be encompassed by the method to be established here. SCE suggests that replacement power costs should be "limited to the costs SCE incurred to replace lost SONGS generation for hours in which SCE had a net-short energy position."[189] SDG&E concurs.[190]

TURN instead suggests that the definition include "*all* the economic harm – in the form of higher revenue requirements and rates – that the SONGS outages would otherwise impose on bundled customers."[191] A4NR supports the TURN recommendation. DRA argues that several different capacity-related and

[189] SCE Phase 1A OB at 5.

[190] SDGE Phase 1A Reply Brief at 3.

[191] TURN Phase 1A OB at 1.

market-related costs should be included because they are "financial consequences" of the outages.[192]

SCE observes that, since California's electric industry restructuring in 1998, utility-owned generation exists in a market-based framework and suggests that our Phase 3 discussion of replacement power cost recovery should be informed by this reality.[193] We agree that the replacement power cost calculations should be based on the realities of the market at the time of the outage.

Our intended, high-level, definition of replacement power costs is the net increase in costs to the utility of meeting its energy and capacity obligations to bundled customers. More specifically, this definition:

- Includes the cost to replace lost, potential generation as well as lost revenues from potential sales. SCE's argument that foregone sales should not be considered has no merit. As proposed by the utilities in this proceeding, the only distinction between a MWh of energy to be replaced and a MWh whose sale is foregone is the utility's position at the relevant hour. The change in net cost to meet customer energy needs due to the lost MWh is only impacted by price at that hour. We do not see a reason to draw any distinction on cost responsibility (as opposed to cost calculation) based on the utility's position.
- Includes capacity and demand response costs allocated to bundled customers for maintaining system reliability in Southern California, to the extent these costs are clearly linked to the SONGS outage. SCE argues that capacity-related charges should not be considered replacement power because they do not "replace the energy output of SONGS."[194] SCE does not provide an affirmative rationale for why non-energy replacement costs

[192] DRA Phase 1A Reply Brief at 3.

[193] SCE-37 at 1-2, SCE Phase 1A OB at 3-4.

[194] SCE Phase 1A OB at 12.

should be treated differently than replacement energy costs. DRA observes that SCE's own testimony contradicts SCE's brief, quoting SCE-8 "These 2012 CAISO charges can be considered replacement costs because they were incurred as a result of power charges assessed to SCE to replace generation from SONGS."[195]

- Includes onsite SONGS loads. SCE argues that replacing onsite loads is not replacement power because SONGS is not a "bundled customer."[196] TURN points out that this "is a distinction without a difference."[197] We find that load from the SONGS facility is not qualitatively different than load from bundled customers, it is simply load that would have been met by SONGS generation had SONGS been generating energy. The cost of meeting this load with non-SONGS energy is a replacement power cost.
- Does not include changes in the value of pre-existing utility hedges, including Congestion Revenue Rights (CRRs), but does include the net cost (e.g. cost net of revenues received) of CRRs purchased in response to the outages. We have a history of encouraging and requiring the utilities to hedge their risks against adverse outcomes. The SONGS outage is one example of the type of adverse outcomes that the utilities should hedge against. In order to avoid creating a perverse incentive against hedging, we will not consider changes in the value of the utilities' portfolio of hedges as replacement power costs. This does not preclude our evaluation of any new hedges in later phases of this or other proceedings.
- Does not include Energy Efficiency (EE) programs. WEM suggests that "surplus" achievements of EE programs saved more energy in 2012 than forecast and that this should be

[195] DRA Phase 1A Reply Brief at 2-3, quoting SCE 8 at 15-16. Note that DRA's reply brief incorrectly attributes the quote to an earlier portion of SCE-8.

[196] SCE Phase 1A OB at 13.

[197] TURN Phase 1A Reply Brief at 11.

> considered in calculating replacement power costs.[198] As SCE observes, "there is no evidence that SCE incurred additional EE costs in 2012 in connection with the outages."[199] We agree. To the extent that EE programs led to loads being lower than forecasted, this may have changed the utilities' net positions (i.e. they were less short or longer than they would have been). Potentially, this could have shifted costs from replacement energy to foregone sales, resulting in a change to net costs. However, the record before us presents no viable means of quantifying this inaccuracy or correcting for it.

For clarity, we divide our discussion of the replacement power method into three categories. Each of these categories would be calculated individually, and then summed together to reach a total replacement power cost for the identified range of dates. The categories are:

1. Replacement energy costs and foregone energy sales,
2. Capacity-related costs, and
3. Other market related costs.

To prepare for using this method in a future phase, we direct each utility to serve exhibits detailing their calculation of replacement power costs according to the method here.

13.2. Replacement Energy Costs and Foregone Energy Sales

The replacement energy and foregone energy sales category represents the net cost to the utility of meeting its bundled energy needs that would have, but for the outage, been provided by SONGS.

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198 WEM Phase 1A OB at 7-8.

199 SCE Phase 1A Reply Brief at 14.

13.2.1. Positions of the Parties

SCE suggests the following formula for each[200] hour in this category:

Q*P = Hourly Replacement Energy Cost or Foregone Sales

Where, Q is the quantity, the portion of the hourly net short (long) position attributed to the outage (in MWh) and P is the price for that hour ($/MWh).[201] Other parties agree with this basic formula.[202] SDG&E adds an additional term "O" that represents:

- "CAISO Allocated costs," in the context of replacement energy costs, [203] which are separable and which we address in the other market costs category below, and
- "lost revenue from RA sales" in the context of foregone sales,[204] which are also separable and which we address in the capacity-related costs section below.

This is a very simple and familiar formula: cost (or lost sales revenue) equals quantity multiplied by price. The calculation of the terms Q and P provokes more controversy.

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[200] Note that SCE proposes a price elasticity adjustment to the term P in some hours. We address this adjustment below.

[201] SCE-37 at 7.

[202] In TURN-14 and in cross-examination, TURN witness Woodruff argues for changes about the calculation of the terms P and Q, implying acceptance of the basic formula. Similarly, in DRA-2, DRA makes a variety of recommendations about the terms P and Q, implying acceptance of the basic formula. Note that earlier versions of the utility testimony, to which DRA-2 responds, show the formula as Q*(P-F), where F represented avoided nuclear fuel costs. DRA-2 suggests that F should be zero. The utilities have agreed, in SCE-37 and SDGE-9B, to set F equal to zero, thus simplifying the formula to Q*P.

[203] SDGE-9B at 5.

[204] SDGE-9B at 7.

13.2.1.1. Q, Quantity

Q represents the amount of energy that must be bought, or could not be sold, for the hour due to the outage. SCE suggests that Q be limited to the amount of energy "that SONGS could have generated had it been available to operate that would have reduced [the utility's] net short position."[205] This limit encompasses two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic operating expectations, and 2) limiting the amount of energy attributed to each utility based on that utility's ownership share of SONGS. No party opposes this limit in concept. Q represents the approximate result of subtracting the utility's actual day ahead energy position from what the position would have been, had SONGS been available to operate. In some hours, the utility would be shorter due to the SONGS outage and have replacement energy costs; in others it would be less long and have foregone energy sales. In still other hours, when the utility was short by less than its share of the SONGS output, the utility had both replacement energy costs and foregone sales. This last possibility is not explicitly referenced in plain language by any party. However, the parties' various arguments about which costs do (or do not) constitute replacement power costs are related. For example, TURN's comments about assuming that "SONGS is always the marginal generation unit" appear to address this possibility.[206] TURN observes that D.05-12-040, which approved the replacement steam generators at

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[205] SCE-2 at 18.

[206] TURN Phase 1A Reply Brief at 3, and 7-8

SONGS, relied on an SCE analysis that assumed the entire generation of SONGS, not limited by the utility's net open position.[207]

How to measure the utility's position is one key question. SCE proposes using the utility's actual position in the day-ahead time frame, specifically, "its final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity".[208] SDG&E agrees.[209] TURN, by contrast, suggests that use of the actual day ahead position creates "downward bias" in the estimate of Q. In response, SCE "contends that there are too many factors to consider to reliably assume a downward bias."[210]

SCE and SDG&E suggest that Q should be calculated using a 2.15% forced outage rate, based on a recent ten year average. SCE also notes this is consistent with the industry average 2% rate reported by the Nuclear Regulatory Commission.[211] SCE suggests that the forced outage rate should be applied equally in all hours (e.g. the assumed lost generation of SONGS would be reduced by 2.15% in each and every hour of the outage).[212] DRA, in contrast suggests a 1.21% forced outage rate, based on a five year average.[213] DRA alternatively suggests using the industry average 2% rate.[214]

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[207] TURN Phase 1A Reply Brief at 5, citing D.05-12-040 at 21-22

[208] SCE-2 at 21.

[209] SDGE-9B at 3

[210] SCE 37 at 19.

[211] SCE-37 at 7; SDGE-9B at 5.

[212] RT 1415:1-3.

[213] DRA-2 at 14.

[214] DRA Phase 1A OB at 6.

SCE suggests that Q should be limited by scheduled refueling and maintenance outages so that only the unit that would not have been on a scheduled outage is counted for replacement power cost calculations. SCE suggests the following scheduled outage dates:[215]

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

No party disputes the dates or the use of these scheduled outages to limit Q during those time periods.

Both utilities suggest that the Q applied to each of them individually should be limited to their respective ownership share of SONGS.[216] No party disputes this.

13.2.1.2. P, Price

P represents the price or the value to the utility of the energy that must be purchased or cannot be sold. SCE suggests using the "SP-15 day-ahead index prices" as reported by Platt's MegaWatt Daily.[217] SCE notes that it procures energy for bundled customers in many different timescales ranging from multi-year to hourly and that there is no single price point that accurately reflects its

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215 SCE-38 at 12.

216 SDGE-9B at 3, SCE-38 at 2-3.

217 SCE-38 at 3. Note that SP-15 refers to the region of the California electric grid to the South of Path 15. SP-15 includes the service territories of both SCE and SDGE, as well as the SONGS facility.

incremental costs.[218] SCE supports its position by asserting that the SP-15 day-ahead index represents costs for the utilities both as buyers and as sellers:

> SP-15 is an appropriate pricing point because the SONGS energy that would have otherwise been produced would have generally served SP-15 load. Additionally, bilateral transactions that SCE would make to cover bundled demand would generally be purchased with an SP-15 delivery or settlement price. Specifically, SP-15 day-ahead index prices are commonly used to settle financial transactions for energy transacted for delivery in southern California.[219]

SDG&E proposes the "SP-15 Trading Hub day-ahead prices" as published by the California Independent System Operator (CAISO), noting that this is the price SDG&E would receive from CAISO for its share of the SONGS output when SONGS was operating.[220] The CAISO trading hub price is calculated for each hour in the day, in contrast to the Platts SP-15 Index proposed by SCE, which is calculated for the on-peak and off-peak periods of each day.[221] SDG&E notes that it is "agreeable" to using the Platts SP-15 Index.[222]

DRA expresses a slight preference for the Platts SP-15 Index proposed by SCE and recommends that the same measure of P be used for both utilities. DRA notes that, although the difference between the two measures proposed by the Utilities is large in some hours, there is very little difference on average. DRA's

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[218] SCE-37 at 16.

[219] SCE-38 at 3.

[220] SDGE-2 at 18.

[221] RT 1442:14-1443:7.

[222] SDGE Phase 1A Reply Brief at 6.

reasoning for this preference is based on the index's use to settle financial and physical transactions in SP-15.[223]

TURN and A4NR suggest that the utilities' respective Default Load Aggregation Point (DLAP) prices should be used for replacement energy costs and the SP-15 Existing Zone Generation Hub (SP-15 EZ-Gen) for foregone sales. The DLAP price represents prices paid by load in the CAISO markets and SP-15 EZ Gen represents prices paid to generators.[224] A4NR's rationale is that ex-post prices are preferable to ex-ante (e.g. the day-ahead Platts) for the purpose of calculating damages and that this approach would be using a load-based price (DLAP) for replacement energy and a generation-based price (SP-15 EZ-Gen) for foregone sales. TURN focuses on the "gap" between the two prices and argues that the simplicity of using a single price does not justify the decrease in accuracy. In support, TURN provides an SCE data response suggesting a 2.5% difference.[225] SCE notes that it is "not opposed" to this proposal "as a matter of principle," but raises the practical objection that the DLAP and SP-15 EZ-GEN prices are not detailed in the record.[226]

For hours with foregone energy sales, SCE proposes that P be modified as (P-E) where E is the "estimated price elasticity impact of SONGS not being available to operate (expressed in $/MWh)."[227] SCE calculated E for on-peak and

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223 DRA-2 at 7-8.

224 A4NR Phase 1A OB at 4-6; TURN Phase 1A OB at 7-9.

225 TURN Phase 1A OB at 8, citing TURN-9, Question 13b.

226 SCE Phase 1A Reply Brief at 19.

227 SCE-37 at 8-9.

off-peak periods for each month based on a regression analysis.[228] SDG&E and TURN each conceptually agree with SCE's approach on this elasticity analysis, but are not able to offer detailed quantitative comment on SCE's estimates. TURN did note that "the results seemed reasonable."[229] No other parties have commented on the subject.

13.2.2. Discussion

We will adopt the formula proposed by SCE and supported by SDGE, TURN, and DRA, including the price elasticity adjustment for foregone sales. Basic economic reasoning suggests this formula: cost (or foregone sales) is equal to the quantity purchased (or not sold) multiplied by the unit price. We apply this formula as summarized in this table:

Hours when the net open position is	**Formula**	**Replacement Energy Cost or Foregone Energy Sales?**
Short	Q_{short} *P =	Replacement Energy Cost
Long	Q_{long} *(P-E) =	Foregone Energy Sales
Short by less than ownership share of SONGS energy	Q_{short}*P =	Replacement Energy Cost
	Q_{long}*(P-E) =	Foregone Energy Sales

13.2.2.1. Q, Quantity

Q is the net open position, in MWh, of the utility, up to its ownership share of SONGS energy. We agree with SCE that Q should be limited by two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic operating expectations, and 2) limiting the amount of

[228] RT 1415:7-24.

[229] RT 1454:17-24; RT 1574: 7-23.

energy attributed to each utility based on that utility's ownership share of SONGS. For hours when the utility's net open position is short (long), it buys (sells) energy to meet the needs of its customers; the amount of this short (long) position up to each utility's ownership share of the lost SONGS energy is the "replacement" energy ("foregone" sales). Amounts beyond the ownership share are ordinary purchases or sales that would have happened regardless of the outage. For hours when the utility's net open position is short by less than its ownership share of SONGS energy, the short position is shown as Q_{short}; the remaining portion of its ownership share is indicated as Q_{long} (i.e. $Q_{short}+Q_{long}$ = Q = the utility's ownership share of SONGS energy). This mathematical treatment of Q recognizes that the total amount of energy replaced (or sales foregone) is independent of the utility's net open position. Stated differently, the sum of energy replaced and sales foregone in each hour is equal to the utility's ownership share of SONGS energy that would have been produced (given operating assumptions discussed below) in that hour.

In all hours, Q should be limited based on realistic operating parameters of SONGS. We agree with parties that these limits are based on both forced and planned outages. We find that each SONGS unit had one planned outage during 2012 and that only the generation of the unit not on outage should be included in Q during the scheduled outage. The planned outages are:

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

We recognize that there is no single "correct" historical timeframe to consider in selecting an appropriate forced outage rate to assume for this analysis. The range presented to us is small (1.21% to 2.15%), changing the calculated costs in this category by less than one percent, and total replacement costs by an even smaller fraction. Further, we note that the replacement steam generators would represent a significant change in the SONGS facility, which calls into question the basic assumption that past experience at SONGS should be the guide. Therefore, we find that it is appropriate to use the industry average 2% forced outage rate reported by the Nuclear Regulatory Commission.

Finally, we agree with SCE and SDG&E that measuring each utility's net open position based on its "final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity" is appropriate. We agree with TURN that this likely does introduce a downward bias because, as SCE admits, the utilities procure energy on many different timescales including products that could have been purchased during the outage for later parts of the outage more than one day forward. However, we see no viable, analytically rigorous alternative based on the record before us.

13.2.2.2. P, Price

P represents the price or the value to the utility of the energy that must be purchased or cannot be sold. We agree with TURN and A4NR that it is worthwhile to use the DLAP price for replacement energy costs and the SP-15 EZ-Gen price for foregone sales. This avoids any "downward bias" associated with using a price that does not match the transaction (i.e. generation based price for a purchase for load, or vice versa). We recognize that this choice imposes a small additional analytic burden on the parties, but believe this work is justified by the increased accuracy in the calculation.

We agree that a price elasticity adjustment, as suggested by SCE, is appropriate for foregone sales, in the form of P-E. The adjustment originally calculated by SCE was intended to modify the Platts SP-15 Index, and will need to be recalculated for the SP-15 EZ-Gen price. However, we see no reason for the basic mechanics of the calculation to change. The Utilities shall calculate a new adjustment, E, for the SP-15 EZ-Gen price, using a regression analysis as presented in work papers and testimony in Phase 1A. The analysis should calculate E for on-peak and off-peak periods of each month

13.3. Capacity-Related Costs

SCE describes three types of capacity costs related to the SONGS outages:[230]

- CAISO Capacity Procurement Mechanism (CPM) charges. CPM charges are allocated to bundled customers based on their load ratio share in certain Transmission Access Charge Areas.
- CAISO Standard Capacity Product (SCP) penalty charges for forced outages. Other Resource Adequacy (RA) resources that qualified for an availability bonus under the SCP during 2012 received bonus payments funded by the SONGS SCP penalty. SCE netted the bonuses it received against its penalty charges.
- Replacement RA capacity. In order to reduce SCP penalty charges, SCE purchased some replacement RA capacity.

CPM costs were incurred related to the outages of both units. The Unit 2 outage, because it was classified as planned, did not result in SCP penalty charges or replacement RA capacity purchases.[231]

SDG&E describes the same three capacity cost categories.[232] However, we must also address the foregone RA sales that SDG&E notes in its testimony.[233]

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[230] SCE-38 at 8-9

[231] SCE-38 at 9

[232] SDGE-9B at 7-8

[233] SDGE-9B at 7

Lost RA value is a broader issue than presented in the SDG&E testimony. Based on the RA rules that were adopted in D.06-07-031 (see table below), the extension of the Unit 2 scheduled outage would prevent that unit from being used to satisfy RA requirements for any month in 2012, after the outage became known. By this rule, both SCE and SDG&E may have lost the value of Unit 2's RA capacity for each month of 2012, excluding January and February for which the RFO was originally scheduled. However, the record before us does not describe which months the Unit 2 RA value was actually lost. It is reasonable to assume that RA value was lost for July to September, when RA requirements are highest. Unit 3's outage, classified as forced rather than scheduled, did not diminish that unit's RA value by this rule. D.06-07-031 summarizes the scheduled outage counting rule as follows:[234]

Time Period	Description of How Resource Would Count at Time of the Showing
Summer May through September	Any month where days of scheduled outages exceed 25% of days in the month, the resource does not count for RAR. If scheduled outages are less than or equal to 25% of the days in the month the resource does count for RAR.
Non-Summer Months October through April	For scheduled outages less than 1 week, the resource counts towards RA obligations. For scheduled outages 1 week to 2 weeks, the amount counted for RAR is prorated using the formula: [1 - (days of scheduled outage/days in month) - 0.25] * NQC in MW = NQC that can count towards an LSE's RA obligation The formula will allow resources to count between 50% and 25% of NQC. For scheduled outages over 2 weeks, the resource does not count for RAR.

Providing RA capacity to meet requirements is a direct cost of serving bundled customers' capacity needs and to the extent that the net cost of meeting RA requirements increased due to the SONGS outage, the increase is a replacement power cost. We find that each utility's ownership share of Unit 2's RA value (Net Qualifying Capacity, or NQC) multiplied by the monthly system

234 D.06-07-031 at 10.

RA price is the appropriate measure of this lost RA value, for July through September in 2012.[235] This measure assumes that in each month either replacement RA was procured or RA sales were foregone, or both. The record before us does not clearly show RA prices for each month. In calculating lost RA value, each utility shall use the average price of its RA-only[236] transactions during calendar year 2012 for July through September of 2012.

DRA notes that both utilities describe the same cost categories.[237]

We find that all three of the capacity-related costs identified by SCE, as well as any foregone RA sales, are replacement power costs. No party disputes that each of these categories represents a capacity cost incurred on behalf of bundled customers as a result of the outage. As discussed above, SCE argues that capacity costs should not be counted as replacement power, but does not provide a persuasive rationale.[238] SCE cites two prior Commission decisions (post-restructuring) that use replacement power costs as a penalty for unreasonable forced outages and uses them to support its assertion that replacement power costs should be limited to replacement energy.[239] SCE neglects to mention that the outages contemplated in these decisions are of a

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235 Even though SONGS is a "local" RA resource, the local premium is only valuable in year-ahead RA contracts and prices. The month-ahead RA program does not explicitly measure local RA.

236 By RA-only, we intend to isolate the price paid for RA, exclusive of other attributes. Therefore, to perform this calculation, the utilities should exclude contracts that include other values, such as: tolling, combined heat and power, renewables, and qualifying facilities.

237 DRA-2 at 16.

238 See: **Error! Reference source not found.**.

239 SCE Phase 1A OB at 4, citing D.10-07-049 and D.11-10-002.

much shorter duration than in the instant case. This is an important distinction due to the incentive for grid operators to take action, for example via CPM, to replace the capacity on outage when that outage may have a long duration. Further, in the market, as it existed in 2012, outages of any duration have a different impact on capacity-related costs than outages during the time periods discussed in the previous decisions. The SCP, and by extension SCP penalties and the need for replacement RA, was created in the CAISO markets in January, 2010 after the outages in the decisions cited by SCE.[240] SDG&E cites one similar decision, but its subject is also a short duration outage prior to the SCP.[241]

TURN suggests adding an additional capacity-related line item from the outage memorandum accounts: the Demand Response (DR) subaccount (line 40).[242] SCE argues that the DR at issue was "exclusively designed as a grid reliability measure" and should not be considered as replacement power because it was not "to meet bundled customer demand."[243] As TURN observes, this distinction is "artificial" – the program was designed to alleviate reliability concerns that were at least in part caused by the SONGS outage.[244] Indeed, this OII directed that the only DR tracked in the subaccount is the DR "specifically

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240 *California Independent System Operator Corporation* (June 26, 2009) 127 FERC ¶ 61,298 (Order Accepting in Part and Rejecting in Part Tariff Revisions Subject to Modification) at 1.

241 SDGE Phase 1A Reply Brief at 2, citing D.12-03-014.

242 TURN-14 at 8.

243 SCE Phase 1A OB at 14, partly referring to RT 1361: 9-10.

244 TURN Phase 1A OB at 9-10, referencing TURN-4 at 15.

implemented to address the loss of SONGS Units 2 and 3 capacity."[245] We find that the DR subaccount is an element of replacement power costs.

13.4. Other Market Costs

In this section, we address other market costs individually.

As discussed above, we view CRRs as a valid component of the Utilities' risk hedging activities. We will not treat net changes in values of previously held CRRs as a replacement power cost. SDG&E notes that it procured CRRs in the monthly CAISO auctions after the outages to manage outage-related congestion costs and that it treats these CRRs as a component of 2012 replacement power costs.[246] We agree -- the net cost of CRRs purchased during 2012 in response to the outages is a replacement power cost.

Real Time Imbalance Charges were charged for the early hours of the outage (in January 31 and February 1 of 2012), when the actual output of SONGS deviated from its schedule in the CAISO markets. Auxiliary Load charges were incurred for load at the facility for the hours when SONGS was not generating during 2012. When SONGS operated, these auxiliary loads were met by SONGS generation. Auxiliary Load is billed by the CAISO through the Real Time Imbalance Charges. Although the Utilities report these two categories differently, they should be proportional to the ownership share of the facility.[247]

The CAISO's Participating Intermittent Resources Program (PIRP) allocates certain charges to all uninstructed negative deviations in the market.

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245 OII.12-10-013 at 12-13.

246 SDGE-9B at 5.

247 RT 1422:25 – 1423:16.

Auxiliary load is treated as such a deviation, and therefore triggers PIRP charges.[248]

The Real Time Imbalance, Auxiliary Load, and PIRP costs would not have been incurred, except for the SONGS outage, in any hour that one or both units would have been scheduled to generate. Therefore we find that these are replacement power costs.

13.5. TURN Proposal for Supplemental Modeling

In its Opening Brief, TURN "offers an alternative approach to the calculation of replacement power costs." The approach is "that each utility be required to perform the specified modeling . . . and make an additional filing subject to comment by the parties." The modeling would calculate energy costs, generation revenues, and CRR costs and revenues by comparing "SONGS OUT" and "SONGS IN" scenarios, based on recorded quantities and actual or estimated prices.[249] TURN argues that this approach avoids "downward biases" found in the approaches suggested by the Utilities.

The Utilities argue against this approach on both procedural (e.g. timing) and practical (e.g. large number of required assumptions) grounds.[250] We agree with the Utilities' practical arguments. Simply stated, we do not have convincing evidence before us that any likely improvement in the accuracy of replacement power cost estimates justifies the considerable extra effort to pursue this modeling approach.

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[248] RT 1424:16 - 1425:8.

[249] TURN Phase 1A OB at 13-15.

[250] See SDGE Phase 1A Reply Brief at 4-6, SCE Phase 1A Reply Brief at 19-23.

13.6. Other Miscellaneous Proposals

WEM alleges that any expenses related to Huntington Beach Units 3 and 4 are illegal, and therefore are not replacement power and should be disallowed.[251] This is outside the scope of this Investigation. Further, SCE explains that it was not directly involved in the Huntington Beach transactions and that CAISO was the purchasing entity.[252]

WEM argues that the Utilities have failed to comply with the Loading Order.[253] This is out of scope.

13.7. Supplemental Exhibit Calculating Replacement Power Costs

In order to implement the replacement power calculations as adopted herein, the Utilities must each recalculate their replacement power costs. As stated above, we intend to have the estimate available for use in future phase of this proceeding (tentatively Phase 3). Therefore, we direct the Utilities to each serve a preliminary Phase 3 exhibit, including summary tables of these calculations within 45 days of today's decision. The summary tables shall contain at least the following details for each month of 2012 and other specified periods, all in 2012 dollars:

- Replacement Energy Cost,
- Foregone Energy Sales,
- Price elasticity adjustment, E, to SP-15 EZ-Gen price for on-peak and off peak periods for each month,

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[251] WEM Phase 1A OB at 4 and 24.

[252] SCE Phase 1A Reply Brief, RT 1391-1393.

[253] WEM Phase 1A OB at 24-25, citing e.g. D.12-01-033.

- CPM Charges,
- SCP Penalty Charges,
- Replacement RA,
- Foregone RA Sales,
- DR Costs,
- PIRP, Real Time Imbalance, and Auxiliary Load Charges, and
- Net Cost of SONGS-Related CRR Purchases.

In addition to the monthly periods, these items shall be calculated for each of the following periods:

- Calendar year 2012,
- Beginning of the SONGS Outage (1/31/2012) through 12/31/2012, and
- Beginning of the SONGS Outage (1/31/2012) through 10/31/2012.

Following the Utilities' submission of these exhibits, parties may serve reply testimony, if, and only if, they allege that the Utilities' calculations do not comply with today's decision or contain calculation errors. Such reply testimony will be due 45 days after the Utility testimony. If any reply testimony is served, rebuttal testimony may be served 20 days later. The assigned ALJs may modify this schedule. Neither the original Utility exhibits nor any reply or rebuttal testimony may be used as an attempt to relitigate any Phase 1A issue. The focus of the exhibits shall be exclusively on recalculating replacement power costs in compliance with today's decision.

14. Revenue Requirements and Refunds

Today's decision segregates 2012 SONGS related costs into three groups: adopted as reasonable costs for recovery, unreasonable costs that shall be refunded in 2014 rates, and costs for which the final reasonableness review shall occur in Phase 3. These adjustments and the resulting 2012 revenue requirement reduction are summarized below:

Summary of Adopted Ratemaking			
100% share, 000s of 2012$			
Cost Category	Adopted	Refund in 2014 Rates	Review in Phase 3
Base O&M	$273,867	$73,880	
SGIR O&M	$18,353		$122,603
Other O&M (Corp. Support, IT, Severance)	$1,663	$4,527	
Subtotal	$293,883	$78,407	$122,603
RFO O&M	$45,077		
Seismic	$4,077		
Capital Expenditures	$134,080		
Capital Additions	($33,520)	($500)	
Replacement Power			To be calculated
2012 Revenue Requirement due to O&M and Capital Adjustments		($93,522) SCE: ($74,222) SDG&E: ($19,300)	

The Utilities shall refund the excess revenue requirement identified by the Commission herein, collected in rates for 2012 expenses, through each utilities' established base rate balancing mechanism, to become effective on January 1, 2014. In addition, for rates collected applicable to SGIR incremental expenses, these funds shall be separately accounted for and interest accrued at the one-year Treasury rate for the benefit of ratepayers should the Commission find in a later phase these funds should also be refunded.

15. Comments on the Proposed Decision

The proposed decision of the ALJs in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ______________ and reply comments were filed on ____________ by __________.

16. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and ALJ Kevin Dudney and ALJ Melanie M. Darling are the assigned ALJs in this proceeding.

Findings of Fact

1. On January 31, 2012 when the Unit 3 (U3) leak was discovered, Unit 2 (U2) was about half-way through its scheduled refueling outage where significant inspections, testing, and repairs take place.

2. On February 12, 2012, SCE confirmed a leak in U3 Steam Generator (SG) tube; additional testing identified several types of tube wear, including significant Tube-to-Tube wear (TTW) in the U-tube region of the SG.

3. On March 13, 2012, SCE was aware that eight U3 tubes failed in-situ pressure testing due to TTW.

4. On March 23, 2012, SCE submitted a SG Return-to-Service (RTS) Action Plan to NRC outlining its commitments to corrective actions before restarting either unit; at the time SCE did not know the cause or extent of tube wear in the steam generator tubes.

5. On March 27, 2012, U.S. Nuclear Regulatory Commission (NRC) sent SCE a Confirmatory Action Letter (CAL) that notified SCE it could not restart either unit until SCE completed a list of actions and NRC completed its review of the actions, including determining causes of TTW.

6. SCE knew the CAL would remain in effect until the NRC had (1) reviewed SCE's response, including responses to staff questions and the results of SCE's evaluations, and (2) NRC had written its conclusion that the units could operate safely without undue risk to public health and safety, and the environment.

7. In early 2012, TTW was unknown; SCE considered TTW as the most significant and complex phenomena, and a key barrier to restart of U2.

8. SCE completed all, or nearly all, of the work related to the U2 refueling outage before SCE knew the potential for serious damage in that unit.

9. In March 2012, SCE developed a plan to postpone, cancel, and re-schedule capital projects; SCE also began work on short-term and long-term repair options.

10. SCE knew or should have known by March 15, when it confirmed tube-to-tube wear in Unit 3, that a potential design defect was present in both units and thus fault could become an issue to rate recovery.

11. SCE's extensive U3 testing completed April 15, 2012, found more than half of the TTW indications in each SG had maximum measured depths exceeding the 35% plugging limit in the technical specifications.

12. On April 23, 2012, SCE issued a U2 tube wear Root Cause Analysis (RCA) which identified the cause of TTW as Fluid Elastic Instability (FEI).

13. On April 26, 2012, SCE Board of Directors was told by SCE managers that U2 return-to-service (RTS) RTS was scheduled for June 1, 2012, and U3 on June 30, 2012.

14. SCE's assumption that U2 could restart in 2012 served as a basis to prioritize work for the plant staff, the operators, and others.

15. SCE did not consider alternative courses of action for U2, other than the restart plan.

16. Cost considerations were not a dominant factor in SCE's analysis of its intended actions for U2.

17. On May 7, 2012, SCE issued U3 RCA which included identification of TTW in U2 and U3.

18. SCE knew or should have known by May 7, 2012, when it confirmed tube-to-tube and three other types of tube wear in Unit 2, that pursuit of a restart plan for U2 was not in the interests of immediately restoring power generation for the benefit of ratepayers

19. In June 2012, SCE began planning to put U3 into Preservation Mode, which maintains the unit in a condition that would allow future refueling and restart, assuming a long-term repair was completed.

20. During the first few months of 2012, SCE worked closely with the NRC, MHI, and its contracted experts to investigate the damage and to develop operational assessments to support a limited restart of U2 for the purpose of testing impact on the SG tubes.

21. SCE's decision to restart U2 was not part of normal operations for an operating generation facility because it was not reasonably foreseeable that the unit would return to full generation in 2012.

22. In July 2012, SCE created a long term repair team for both units.

23. On October 3, 2012, SCE submitted its response to CAL; NRC identifies 6 -7 month window for review, inspections, response to staff information requests, public meetings, etc.

24. On December 5, 2012, the Atomic Safety Licensing Safety Board held hearing to determine whether SCE will need a license amendment to try U2 restart plan

25. On December 14, 2012, Mitsubishi Heavy Industries (MHI), which designed & manufactured the replacement steam generators, sent two progress letters to SCE regarding development of long-term repair options.

26. On December 20, 2012, MHI provides SCE with long-term repair options and recommendations.

27. The primary purpose of SCE's U2 restart plan was a limited theoretical test to gather data for long-term repair options, not for electric generation.

28. SCE bills SDG&E for its pro rata share of SONGS-related expenses; SG&E also has internal-only expenses related to its ownership interest in SONGS.

29. SCE has not credited the $3.96 million in 2012 savings from staff reductions to the overall calculation of O&M.

30. Of the total $488,702 million recorded (100% $2012) for O&M costs, $347.747 million is recorded as Base-Routine, $140.955 million as SGIR-related.

31. By early May 2012, SCE knew or should have known that it was not reasonably foreseeable that Unit 2 would return to producing electricity in 2012 or even that a short-term restart was viable.

32. In order to reasonably account for O&M costs incurred as a result of SCE's not well-considered decision to maintain all, or nearly all, operating staff through the end of 2012, O&M costs recoverable in rates should gradually decrease beginning in June 2012.

33. SCE recorded $140.855 million (100%) for 2012 incremental SGIR expenses, including $8.555 million re-allocated post-hearing from Base O&M.

34. SCE collected some SGIR-related expenses in rates because it viewed them as normal O&M or capital costs.

35. The seismic studies approved by D.12-05-004 are not directly related to relicensing; they are related to regulatory requirements.

36. The Commission preliminarily authorized SCE to make $189.2 million ($2012, 100%) in SONGS-related capital expenditures; SCE actually recorded a total of $167.6 million for all types of projects, including the RFO and SGIR expenses.

37. More than $89 million (53.5%) of total capital expenditures occurred between January and April, 2012.

38. Some capital expenditures were necessary during 2012, even though the reactor units were not operating, because the NRC operating license requires SCE to maintain many systems in order to protect the safety of the plant, its workers and the public.

39. SCE's effort to suspend, cancel, and re-schedule some projects was inadequate to reflect the overall reduction of capital projects that should have occurred at SONGS.

40. Rate-based 2012 capital revenue requirements exceed preliminary allowed amounts for both SCE and SDG&E by a combined total of $41.8 million.

41. SCE's evidence is incomplete as to the extent that SGIR-related and U2 RFO capital projects are recorded as in-service and added to rate base in 2012.

42. The evidence does not establish that SCE knew in 2012 that it would decide in 2013 to permanently shut down the SONGS facility.

43. SCE did not calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012, but said it could develop an approximate estimate using the lead-lag days adopted in the GRC.

44. SDG&E recorded $60.492 million of SONGS-related costs not included in the SONGS portion of SCE's 2012 GRC or in SCE's OII testimony.

45. The costs of SCE's Customer Outreach and Emergency preparedness programs are part of the company-wide GRC review, primarily through budgets for Local Public Affairs and Corporate Communications.

46. The requirements for emergency preparedness followed by SCE, and other operators of commercial nuclear plants in the United States, are established by the NRC, Federal Emergency Management Agency (FEMA), and certain state agencies.

47. It is in the public interest for SCE to expand its public education about SONGS and the future decommissioning beyond the 20-mile zone, to 50 miles, for the immediate future.

48. In 2011, SCE expected two RFOs to occur in 2012 and included $102.606 million in 2012 rates for these RFOs (100% share).

49. SDG&E included $28.7 million in rates for its share of two RFOs in 2012.

50. Only one RFO, the U2 Cycle 17 RFO, occurred during 2012 at a cost of $45.1 million, resulting in an effective over-collection of $57.5 million (100% share).

51. SDG&E recorded $9.1 million for the 2012 RFO, $19.6 million less than collected.

52. The utilities' costs of $45.1 million (100% share) for the U2 Cycle 17 RFO during 2012 were reasonably incurred.

53. Any amount collected beyond the $45.1 million for 2012 RFOs is an over-collection.

54. SCE seeks to refund its over-collection via its 2013 ERRA forecast proceeding.

55. SDG&E has refunded its over-collection via Advice Letter 2416-E.

56. SCE's decision to place new fuel in the U2 core during U2 Cycle 17 RFO was reasonable.

57. For purposes of calculating 2012 replacement power costs in Phase 1A of this proceeding, the definition of replacement power is the net increase in costs to the utility of meeting its energy and capacity obligations to bundled customers. This definition includes: the cost of replacing potential generation and lost revenues from potential sales; capacity and demand response costs allocated to bundled customers, to the extent these costs are clearly linked to the SONGS outage; the net cost of Congestion Revenue Rights (CRRs) purchased in response to the outages; and onsite SONGS loads. This definition excludes energy efficiency programs and the changes in the value of pre-existing utility hedges including CRRs.

58. The formula detailed in the following table is appropriate for calculating replacement energy cost and foregone sales, where: Q represents the SONGS outage-related portion of the hourly net open position in megawatt-hours, P represents the energy price in dollars per megawatt-hour, and E represents a price elasticity adjustment in dollars per megawatt-hour.

<table>
<tr><th>Hours when the net open position is</th><th>Formula</th><th>Replacement Energy Cost or Foregone Energy Sales?</th></tr>
<tr><td>Short</td><td>Q_{short} *P =</td><td>Replacement Energy Cost</td></tr>
<tr><td>Long</td><td>Q_{long} *(P-E) =</td><td>Foregone Energy Sales</td></tr>
<tr><td rowspan="2">Short by less than ownership share of SONGS energy</td><td>Q_{short}*P =</td><td>Replacement Energy Cost</td></tr>
<tr><td>Q_{long}*(P-E) =</td><td>Foregone Energy Sales</td></tr>
</table>

59. Q is appropriately limited by two concepts: 1) limits to the amount of energy that SONGS would have generated in each hour based on realistic

operating expectations, and 2) limiting the amount of energy attributed to each utility based on that utility's ownership share of SONGS.

60. Each SONGS unit had one planned outage during 2012, for the dates below.

Unit 2	1/10/2012 through 3/4/2012
Unit 3	10/8/2012 through 12/2/2012

61. It is reasonable that only generation for the unit not on outage be included in Q during each of the scheduled outages.

62. It is appropriate to use the industry average 2% forced outage rate reported by the Nuclear Regulatory Commission for calculating Q.

63. Measuring each utility's net open position (Q) based on its final assessed net open energy position prior to the commencement of its day-ahead spot market trading activity is appropriate.

64. It is reasonable to use the Default Load Aggregation Point (DLAP) price for replacement energy costs and the South of Path 15 Existing Zone Generation Hub (SP-15 EZ-Gen) price for foregone sales.

65. A price elasticity adjustment is appropriate for foregone sales.

66. There are five types of capacity-related costs that are replacement power costs: California Independent System Operator (CAISO) Capacity Procurement Mechanism (CPM) charges, CAISO Standard Capacity Product (SCP) penalty charges, replacement Resource Adequacy (RA) capacity, foregone RA sales, and Demand Response (DR) specifically implemented to address the loss of SONGS.

67. It is reasonable to assume that RA value was lost for July to September of 2012, when RA requirements are highest.

68. Each utility's ownership share of Unit 2's RA capacity value (Net Qualifying Capacity) multiplied by the monthly system RA price is the appropriate measure of this lost RA value, for July through September in 2012.

69. It is reasonable for each of the Utilities to use the average price of its RA-only transactions concluded during calendar year 2012 for July through September of 2012, or any month therein, as the RA price for July through September 2012.

70. The Real Time Imbalance, Auxiliary Load, and PIRP costs would not have been incurred, except for the SONGS outage, in any hour that one or both units would have been scheduled to generate, and therefore these costs are replacement power costs.

Conclusions of Law

1. During January and February, SCE acted as a prudent operator of SONGS to detect the U3 leak, identify the source of the leak, inspect all of the U2 and U3 tubes for damage, investigate the causes of excessive and unexpected wear, and to assess whether repair is a reasonable option.

2. SCE's decision-making process was not reasonable or sound when the utility decided after May 7, 2012 to pursue RTS for U2 as soon as possible.

3. SCE's decision in May 2012 to retain the staff required for a fully operational facility, resulting in large O&M expenses, was unreasonable.

4. The record does not establish that costs associated with the restart and long-term repair options (SGIR) are routine O&M for which it would be just and reasonable to collect immediate recovery from ratepayers.

5. It is reasonable for savings realized from employee layoffs to be credited to ratepayers as part of the overall costs subject to rate recovery for 2012 O&M.

6. Beginning in June 2012, 10% of O&M shall be re-allocated to SGIR for further review as SGIR-related expenses in Phase 3, followed by 20% in July and so on until November and December 2012 when 40% of recorded O&M will remain in rates.

7. The total amount of reasonable 2012 SONGS-related O&M is $292.030 million, $96.97 million less than the amount preliminarily authorized in the GRC ($389.0 million).

8. It is reasonable to defer the final reasonableness review of 2012 incremental costs related to the outages of the steam generators to Phase 3 in the context of the overall SGRP and SCE's management of the project.

9. It is reasonable to apply a 20% reduction to recorded capital expenditures to establish the necessary and reasonable amount to maintain the units in a safe and secure condition, or to meet federal and state regulatory requirements.

10. It is reasonable for ratepayers to receive interest on previously collected SGIR expenses which have not yet been found by the Commission to be reasonable, nor were they preliminarily authorized by the Commission.

11. Approximately $134.08 million (80%) of 2012 total recorded capital expenditures are reasonable, including expenditures related to the U2 RFO.

12. It is reasonable to apply the 20% reduction in approved capital expenditures as a proxy for excess capital projects moved to rate base in 2012, to remove this amount from the rate base, and the associated revenue requirement is determined to be unreasonable for 2012.

13. It is not reasonable to impute knowledge of SCE's June 2013 decision to shut down SONGS permanently, to SCE during 2012.

14. It is not reasonable to prevent the Utilities from accruing AFUDC in 2012 for SONGS-related Construction Work In Progress.

15. In order to capture additional SONGS-related costs, it is reasonable for SCE to calculate a separate estimate of Cash Working Capital requirements attributable to SONGS in 2012.

16. The Commission's interim finding that SDG&E's internal SONGS-related costs of $60.5 million are reasonable does not preclude the Commission's subsequent review of SGRP and SGIR costs from the final review to come.

17. There is no evidence that that SCE has failed to comply with any federal, state, or county regulations regarding emergency preparedness.

18. It is reasonable for SCE to expand its public outreach activities into the 50-mile radius surrounding SONGS during the transition to decommissioning activities.

19. The ratemaking treatment approved by D.12-05-004 for the SONGS seismic studies should not be changed by today's decision.

20. The utilities should be authorized to recover their actual, reasonably incurred costs for the U2 Cycle 17 RFO of $45.1 million (100% share).

21. The utilities should be required to refund to ratepayers any amount previously collected for 2012 RFOs beyond the actually incurred $45.1 million.

22. To prepare for using the replacement power cost calculation method adopted here, the utilities should be required to serve Phase 3 exhibits detailing their calculation of their replacement power cost using the adopted method. The exhibits should also include other detailed information as specified in the body of today's decision.

23. Reply and rebuttal testimony in response to the Utilities' Phase 3 replacement power exhibits should be permitted if, and only if, any party alleges that the Utilities' exhibits do not comply with today's decision or contain calculation errors.

24. No party should be allowed to use the Phase 3 replacement power exhibits to relitigate any Phase 1A issue.

25. The assigned ALJs should be permitted to modify the schedule for the Phase 3 replacement power testimony.

ORDER

IT IS ORDERED that:

1. Application 13-01-016 is granted to the extent set forth in this Decision. Southern California Edison Company's preliminarily allowed 2012 revenue requirement derived from expenses related to the San Onofre Nuclear Generation Stations is reduced by approximately $74 million. Southern California Edison Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the revised company revenue requirement of $5.671 billion as set forth in Appendix G, effective January 1, 2012.

    a. As part of the revenue requirement calculation ordered in paragraph 3, Southern California Edison Company shall calculate a separate estimate of Cash Working Capital requirements attributable to San Onofre Nuclear Generation Stations in 2012 using the lead lag and other relevant inputs adopted for the company in its 2012 General Rate Case.

2. Application 13-03-013 is granted to the extent set forth in this Decision. San Diego Gas & Electric Company's preliminarily allowed 2012 revenue requirement derived from expenses related to the San Onofre Nuclear Generation Stations is reduced by approximately $19 million. San Diego Gas & Electric Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the revised revenue requirement effective

January 1, 2012.

a. San Diego Gas & Electric Company is also authorized to recover in rates $60.4 million in additional expenses incurred solely as a result of San Diego Gas & Electric Company's ownership interest and oversight responsibilities, and which are not included in Southern California Edison Company's invoiced pro rata share of San Onofre Nuclear Generation Stations operational expenses.

3. Within 10 days of the effective date of this decision, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the Utilities), in consultation with the Commission's Energy Division, shall each prepare a revised 2012 revenue requirement based on input of the reduced expenses and reduced rate base authorized herein, into each utility's 2012 General Rate Case model. The Utilities shall each submit the revenue requirement to the Commission as a Tier 1 Advice Letter, and serve the Advice Letter on the service list for these consolidated proceedings.

4. Within 20 days of the effective date of this decision, Southern California Edison Company and San Diego Gas & Electric Company shall submit revised tariff sheets to implement the revised 2012 revenue requirement. The revised tariff sheets shall become effective on filing, subject to a finding of compliance by the Commission's Energy Division, and shall comply with General Order 96-B.

5. Southern California Edison Company and San Diego Gas & Electric Company shall re-calculate the amount of 2012 operations and maintenance expenses directly related to steam generator inspection and repair, as set forth in this Decision, and identify the portion which was previously collected in rates. The Utilities shall separately account for the steam generator inspection and repair expenses previously collected, and those not yet collected in rates, in the San Onofre Nuclear Generation Station (Outage) Memorandum Accounts.

6. The Utilities shall accrue interest on collected steam generator inspection and repair funds at the one-year Treasury rate for the benefit of ratepayers to protect the value of the funds until the Commission completes its Phase 3 review of all expenses related to the replacement steam generators. All steam generator inspection and repair expenses, including those not recovered by the Utilities in rates, shall continue to be tracked in the San Onofre Nuclear Generation Station (Outage) Memorandum Accounts.

7. Within 90 days of the effective date of this decision, Southern California Edison Company shall develop a strategy for expanding public education activities about San Onofre Nuclear Generation Station and the future decommissioning to the public within a 50-mile radius of San Onofre Nuclear Generation Stations through 2016. Southern California Edison Company shall be particularly sensitive to pockets of alternative language users and coordinate with community-based organizations to ensure wide distribution of information to the public about the status of San Onofre Nuclear Generation Stations and its planned decommissioning. Southern California Edison Company shall submit the proposed strategy and implementation schedule to the Commission as an Information-Only Filing, as defined in Section 3.9 of the General Rules of General Order 96-B and serve it on the service list for these consolidated proceedings.

8. The ratemaking treatment approved by Decision 12-05-004 for the seismic studies shall remain unchanged by today's decision.

9. Southern California Edison Company and San Diego Gas & Electric Company are authorized to recover their respective shares of $45.1 million (100% share) for the Unit 2 Cycle 17 Refueling Outage that occurred in 2012.

10. Southern California Edison Company and San Diego Gas & Electric Company shall refund to ratepayers any amount previously collected for 2012

Refueling Outages beyond this $45.1 million.

a. Southern California Edison Company shall refund any remaining over-collection in its 2014 rates to the extent that the refund has not previously occurred in 2013 rates based on its 2013 Energy Resource Recovery Account filings.

b. San Diego Gas & Electric Company shall refund any remaining over-collection in its 2014 rates to the extent that the refund has not previously occurred in 2013 rates based on its Advice Letter 2416-E.

11. Within 45 days of the effective date of this decision Southern California Edison Company and San Diego Gas & Electric Company shall each serve a preliminary Phase 3 exhibit, including summary tables of their 2012 replacement power cost calculations according to the method adopted in today's decision. The summary tables shall include at least the details specified below:

a. Replacement Energy Cost;

b. Foregone Energy Sales;

c. Price elasticity adjustment, E, for on-peak and off peak periods for each month;

d. Capacity Procurement Mechanism Charges;

e. Standard Capacity Product Penalty Charges;

f. Replacement Resource Adequacy;

g. Foregone Resource Adequacy Sales;

h. Demand Response Costs;

i. Participating Intermittent Resource Program, Real Time Imbalance, and Auxiliary Load Charges; and

j. Net Cost of Related Congestion Revenue Rights Purchases.

12. Following the Utilities' submission of these preliminary Phase 3 exhibits, parties may serve reply testimony, if, and only if, they allege that the Utilities' calculations do not comply with today's decision or contain calculation errors.

Such reply testimony will be due 45 days after the Utility testimony. If any reply testimony is served, rebuttal testimony may be served 20 days later. The assigned ALJs may modify this schedule. Neither the original Utility exhibits nor any reply or rebuttal testimony may be used as an attempt to relitigate any Phase 1A issue.

13. All rulings made by the assigned Commissioner and/or Administrative Law Judge(s) to date are affirmed, all motions applicable to Phase 1 and Phase 1A and not yet ruled upon are deemed denied.

14. Investigation 12-10-013, Application 13-01-016, Application 13-03-005, Application 13-03-013, and Application 13-03-014 remain open.

This order is effective today.

Dated ______________________________, at San Francisco, California.

Appendix A

Southern California Edison Company's Year End 2012 SONGSMA Report

SOUTHERN CALIFORNIA EDISON COMPANY
SONGS 2&3 Outage Memorandum Account - February 2013
I.12-10-013
($000)

		2012												
		January	February	March	April	May	June	July	August	September	October	November	December	YTD
1.	**I. Base Capital Cost Subaccount**													
2.	Capital Expenditures	10,229	38,143	13,727	9,450	7,984	6,970	8,853	8,048	8,647	5,306	10,392	5,857	133,606
3.	CWIP Balance	284,283	330,425	194,542	173,272	173,400	182,300	191,100	191,900	198,800	203,466	210,279	216,652	216,652
4.	Rate Base - End of Month	559,991	553,385	636,466	643,875	637,547	657,441	645,621	649,052	636,617	621,858	625,236	638,655	
5.	Depreciation	5,494	5,491	5,505	6,483	7,290	7,106	7,054	7,090	7,143	7,161	7,195	7,319	80,331
6.	Taxes on Income	(1,069)	1,073	43,921	22,886	4,899	775	538	(16,702)	1,268	(1,300)	(10,262)	(264)	45,762
7.	Ad Valorem Taxes	493	493	493	493	493	493	601	601	601	601	601	601	6,568
8.	Return	4,099	4,053	4,331	4,661	4,665	4,714	4,744	4,713	4,680	4,581	4,540	4,601	54,382
9.	Subtotal Revenue Requirement	9,017	11,110	54,250	34,522	17,347	13,089	12,937	(4,298)	13,693	11,043	2,074	12,257	187,042
10.	**II. Steam Gen Replacement/Removal Capital Cost Subaccount**													
11.	Capital Expenditures - Replace	(689)	231	1,916	291	1,409	(1,473)	71	690	621	42	1,585	6,567	11,268
12.	Capital Expenditures - Remove	-	-	127,343	-	-	(33,595)	-	-	1,057	11,671	49	1,257	107,783
13.	CWIP Balance - Replace	90,600	91,300	-	128,479	98,314	-	93,900	95,300	-	(11,313)	1,198	6,749	6,749
14.	CWIP Balance - Remove	-	-	94,805	-	-	93,700	-	-	94,800	57,041	251	1,465	1,465
15.	Rate Base - Replace - End of Month	528,435	524,141	519,846	515,552	511,258	510,188	505,868	501,548	498,977	494,640	479,247	475,058	
16.	Rate Base - Remove - End of Month	(31,787)	(31,806)	(31,933)	(31,956)	(32,038)	(31,970)	(31,977)	(32,014)	(32,066)	17,212	68,945	68,349	
17.	Depreciation	4,211	4,211	4,211	4,211	4,211	4,211	4,238	4,238	4,238	4,253	4,695	5,077	52,007
18.	Taxes on Income	273	273	273	273	273	273	532	532	532	532	532	527	4,821
19.	Ad Valorem Taxes	1,699	1,685	1,640	1,654	1,623	1,652	1,625	1,601	1,583	1,628	499	1,973	18,863
20.	Return	3,632	3,600	3,568	3,537	3,505	3,485	3,466	3,434	3,409	3,563	3,859	3,974	43,032
21.	Subtotal Revenue Requirement	9,815	9,769	9,693	9,674	9,612	9,621	9,861	9,805	9,762	9,976	9,584	11,551	118,722
22.	**III. O&M Expense Subaccount**													
23.	Fuel (ERRA)	4,522	(18)	(15)	(23)	(13)	(14)	40	-	-	-	-	177	4,657
24.	Fuel Carrying Costs (ERRA)	194	182	182	182	185	303	439	368	365	358	360	361	3,480
25.	Replacement Power (ERRA)	4,432	8,372	9,692	11,356	6,393	9,244	20,231	27,535	26,115	21,534	15,622	14,522	175,048
26.	Capacity Payments (ERRA)	-	1,657	2,692	1,434	4,588	4,384	3,748	4,310	4,047	3,674	903	1,704	33,141
27.	Foregone Sales Revenue (ERRA)	3,551	10,306	7,120	8,684	14,247	11,196	6,905	6,804	5,942	918	783	13,272	89,728
28.	Routine O&M	26,242	25,563	22,460	22,404	22,244	19,399	21,781	21,103	45,499	27,242	19,207	27,345	300,489
29.	Refueling (1 in 2012)	14,738	13,873	4,152	707	838	(91)	33	212	(142)	273	321	341	35,255
30.	Seismic Safety	11	145	338	370	100	148	198	471	257	314	267	642	3,261
31.	Investigation	-	4,534	11,951	12,614	3,982	7,212	-	22,327	4,438	-	-	-	67,059
32.	Repairs - After Outage	-	2,074	1,481	3,090	1,291	-	9,542	-	9,823	-	-	-	27,302
33.	Regulatory - After Outage	-	-	-	-	144	121	156	48	51	473	2,427	-	3,421
34.	Defueling	-	-	-	-	-	-	-	122	651	158	-	-	932
35.	Litigation	-	-	-	-	-	603	39	79	49	862	2,307	1,783	5,722
36.	Payroll Taxes	1,305	1,555	1,226	1,065	1,209	993	952	1,205	900	1,146	928	959	13,442
37.	Other (Pensions, PBOP, Insurance)	2,762	3,155	1,374	2,133	2,192	989	1,256	2,568	907	1,796	1,107	1,671	21,909

SOUTHERN CALIFORNIA EDISON COMPANY
SONGS 2&3 Outage Memorandum Account - February 2013
I.12-10-013
($000)

		2012												
		January	February	March	April	May	June	July	August	September	October	November	December	YTD
38.	Subtotal	57,757	71,398	62,655	64,015	57,399	54,489	65,320	87,151	98,902	58,750	44,231	62,777	784,845
39.	**IV. Huntington Beach Subaccount**	-	519	1,543	3,295	2,356	1,801	689	1,587	2,246	991	1,001	817	16,845
40.	**V. Demand Response Subaccount**	-	-	-	-	-	32	171	47	12	2,424	37	46	2,769
41.	**VI. Transmission Upgrades Subaccount**													
42.	Capital Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
43.	Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
44.	Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
45.	Taxes on Income	-	-	-	-	-	-	-	-	-	-	-	-	-
46.	Ad Valorem Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
47.	Return	-	-	-	-	-	-	-	-	-	-	-	-	-
48.	Subtotal Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-
49.	O&M (if any)	-	-	-	-	-	-	-	-	-	-	-	-	-
50.	**VII. Authorized Revenue Requirment Subaccount**													
	Monthly Revenue Requirement GRC	30,383	26,399	32,874	29,387	30,881	43,832	58,276	72,223	63,257	52,797	29,885	27,893	498,087
	Monthly Revenue Requirement SGR	7,030	6,108	7,606	6,799	7,145	10,141	13,483	16,710	14,635	12,215	6,914	6,453	115,239

NOTES:

1. All amounts shown above reflect SCE's 78.21% share
2. Severance costs (SCE Share) included in Line No. 28 reflect an accrued amount of $36.0 million, however only $13.8 million has been paid out as of December 31, 2012.
3. Received $45.4 million (100% share) from MHI and this amount is not included above.
4. The costs shown in the Demand Response subaccount also include other ISO market costs that were incurred as a result of the outages.
5. SCE is still in the process of identifying any Transmission upgrade costs incurred as a result of the outages. Any amounts will be included in the next reporting cycle.

(End of Appendix A)

Appendix B

San Diego Gas & Electric Company's Year End 2012 SONGSMA Report

SAN DIEGO GAS & ELECTRIC COMPANY
SONGS 2&3 Outage Memorandum Account
I.12-10-013
($000)

	2012												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1 I. Sunk Capital Cost Subaccount													
2 Capital Expenditures	3,322	10,392	2,468	1,795	2,167	3,864	3,281	1,994	1,996	2,818	2,138	2,241	38,475
3 CWIP	98,813	109,820	108,961	113,845	116,440	119,138	120,983	125,286	130,634	92,230	112,139	110,855	110,855
4 Rate Base	103,504	104,677	105,159	106,805	107,782	105,458	103,472	103,344	102,936	103,797	113,965	121,857	106,896
5 Depreciation	817	827	835	851	862	852	843	845	847	856	939	1,010	10,385
6 Taxes on Income	337	342	344	349	355	348	339	339	337	334	303	341	4,067
7 Ad Valorem Taxes	-	-	-	1,940	-	-	-	-	-	-	-	1,977	3,917
8 Return	725	733	736	748	755	738	724	723	721	727	798	853	8,979
9 Subtotal Revenue Requirement	1,879	1,902	1,914	3,887	1,971	1,939	1,907	1,908	1,905	1,917	2,040	4,181	27,348
10 II. Steam Gen Replacement/Removal Capital Cost Subaccount													
11 Capital Expenditures - Replace	61	(982)	440	5	77	802	1,076	(172)	(798)	(469)	12,577	248	12,863
12 Capital Expenditures - Remove	849	714	189	187	325	187	190	201	194	199	(12,420)	(134)	(9,320)
13 Rate Base - Replace	133,780	132,238	130,887	130,029	128,990	128,347	128,197	127,556	125,980	124,261	127,896	129,997	129,013
14 Rate Base - Remove	-	-	-	-	-	-	-	-	-	-	3,713	12,303	1,335
15 CWIP Balance - Replace	-	-	-	-	-	-	-	-	-	-	-	137	137
16 CWIP Balance - Remove	27,349	28,063	28,251	28,439	28,764	28,951	29,141	29,342	29,536	29,735	9,826	-	-
17 Depreciation	1,062	1,059	1,057	1,058	1,059	1,062	1,069	1,072	1,068	1,064	1,107	1,152	12,888
18 Taxes on Income	418	413	407	404	400	398	397	395	390	385	369	414	4,789
19 Ad Valorem Taxes	-	-	-	153	-	-	-	-	-	-	-	343	496
20 Return	937	926	916	910	903	898	897	893	882	870	921	996	10,949
21 Subtotal Revenue Requirement	2,417	2,397	2,380	2,526	2,362	2,358	2,363	2,360	2,341	2,318	2,397	2,905	29,123
22 III. O&M Expense Subaccount													
23 Fuel (ERRA)	1,228	(5)	(4)	(6)	(3)	(3)	(4)	(4)	24	-	-	-	1,223
24 Fuel Carrying Costs (ERRA)	10	10	12	13	14	16	20	20	21	19	18	19	192
25 Replacement Power (ERRA)	(5,312)	3,236	4,814	5,333	6,457	5,859	7,618	8,082	8,992	9,849	8,623	8,698	72,249
26 Capacity Payments (ERRA)	6	205	116	411	279	381	378	560	579				2,916
27 Foregone Sales Revenue (ERRA)							206	206	206	46	46	46	756
28 Routine O&M	6,255	7,054	5,914	5,890	6,044	5,099	5,698	5,519	6,402	7,460	5,079	7,145	73,559
29 Refueling (1 in 2012)	3,513	3,828	1,093	186	228	(24)	9	55	(20)	75	85	89	9,116
30 Seismic Safety	3	40	89	97	27	39	52	124	37	87	71	168	832
31 Investigation	-	1,251	3,147	3,317	1,082	1,896	-	5,839	625	-	-	-	17,155
32 Repairs - After Outage	-	572	390	812	351	-	2,496	-	1,382	-	-	-	6,004
33 Regulatory - After Outage	-	-	-	-	39	32	41	13	7	130	642	-	903
34 Defueling	-	-	-	-	-	-	-	32	92	43	-	-	167
35 Litigation	-	-	-	-	-	-	-	-	-	-	-	-	-
36 Payroll Taxes	350	423	347	287	319	292	256	337	242	301	265	324	3,744
37 Other (Pensions, PBOP, Insurance)	2,732	3,197	2,774	2,620	2,850	2,551	2,287	3,092	2,239	2,729	2,302	2,253	31,624
38 Subtotal	8,785	19,811	18,693	18,960	17,687	16,139	19,056	23,874	20,826	20,738	17,130	18,741	220,440
39 IV. Huntington Beach Subaccount	-	-	-	-	-	-	-	-	-	-	-	-	-
40 V. Demand Response Subaccount													
41 Peak Time Rebate - Small Commercial (PTRA)	-	-	-	-	-	-	-	-	-	-	-	-	-
42 Demand Bidding Program (DBP 2012)	-	-	-	-	-	-	-	-	-	-	-	-	-

SAN DIEGO GAS & ELECTRIC COMPANY
SONGS 2&3 Outage Memorandum Account
I.12-10-013
($000)

	2012												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
43 Marketing, Education & Outreach (ME&O)	-	-	-	-	1	-	0	1	38	45	5	3	91
44 Subtotal DR	-	-	-	-	1	-	0	1	38	45	5	3	91
45 VI. Transmission Upgrades Subaccount													
46 Capital Expenditures	-	-	-	-	-	(8)	9	93	1,245	137	653	883	3,013
47 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
48 Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
49 Taxes on Income	-	-	-	-	-	-	-	-	-	-	-	-	-
50 Ad Valorem Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
51 Return	-	-	-	-	-	-	-	-	-	-	-	-	-
52 Subtotal Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-
53 O&M (if any)	-	-	-	-	-	-	-	-	-	-	-	-	-
54 VII. Authorized Revenue Requirement Subaccount													
55 Monthly Revenue Requirements	16	16	16	16	16	16	16	16	16	16	16	15	185
56 VIII. Adders to SCE-Originated SONGS Costs													
57 SCE-Billed Costs Not Included by SCE in § III	(12)	3,762	(73)	(101)	(18)	(46)	(39)	(128)	(33)	(46)	106	902	4,274
58 SDG&E Portion of Nuclear and Related Insurance	-	-	956	-	463	-	-	945	-	-	-	-	2,364
59 SDG&E Portion of SONGS Site Easement	-	-	-	20	-	-	-	-	-	-	-	-	20
60 SDG&E Overheads on SONGS Costs - Capital (Adder to § I)	786	964	628	889	574	775	886	958	1,003	1,069	773	678	9,983
61 SDG&E Overheads on SONGS Costs - O&M (Adder to § III)	624	526	550	1,057	661	735	860	723	679	1,197	930	974	9,515
62 Net Impact of Billing Lag (Temporary Adder to §§ I & III)	2,038	(9,161)	(5,575)	10,830	675	491	(637)	(3,352)	1,222	5,777	(1,375)	(4,416)	(3,484)
63 IX. SDG&E Direct Cost of SONGS Oversight													
64 Operational and Financial Oversight Team	45	90	62	40	69	43	56	54	51	60	40	59	668

NOTES
All amounts shown reflect SDG&E's actual costs for SONGS, including 20% share of SONGS 100%-level costs incurred by SCE plus contractual overheads.
SGRP costs reported net of 20% of estimated removal and disposal costs for the original steam generators granted in SDG&E's 2006 SGRP Decision D.06-11-026.
SCE advance bills SDG&E for the month and trues-up previous advance bills. The "Lag Adjustment" converts SONGS data for the billing process to match actual SDG&E posting periods.
SCE 's invoices to SDG&E do not allow O&M costs to be broken out into the cost categories shown for O&M. Figures were provided by SCE, who allocated the SDG&E prorated billing based upon SCE's reported costs.
SDG&E has not yet received a 2012 GRC decision authorizing a revenue requirement. Revenue Requirement based on AL 2302-E filed November 10, 2011, pending a final GRC decision.
SDG&E's SONGS Oversight includes estimated overheads for Payroll Tax, Incentive Compensation Plan ("ICP"), Pension & Benefits, Workers' Compensation, Vacation & Sick Leave, PLPD Insurance, and Purchasing.
Property tax amounts are estimated based on an allocation of total property taxes paid.
Replacement Power (ERRA) amount estimated for 2012 excludes lost generation replacement costs for planned refueling and maintenance outage for 01/10/12 through 03/05/12 for SONGS Unit 2 of $5,039K.
Capacity Payments (ERRA) amount estimated for CPM charges and Resource Adequacy (RA) purchases.

SAN DIEGO GAS & ELECTRIC COMPANY
SONGS 2&3 Outage Memorandum Account
I.12-10-013
($000)

SONGS COSTS BY AUTHORIZATION CATEGORY

		As Reported	SCE GRC	SDG&E GRC	SGRP	ERRA	Other BA- DR	Other BA - NGBA	Transmission Owner Tariff	NEW
			D.12-11-051	Pending	D.05-12-040	D.12-07-006 D.12-08-007 D.12-12-022	Resolutions E-4502, E-4511, D. 12-14-045	AL-2302		
1	I. Sunk Capital Cost Subaccount									
2	Capital Expenditures	38,474.9	$39,250.80	$10,009.60						
3	CWIP	110,854.7	110,854.7							
4	Rate Base	106,896.3	106,896.3							
5	Depreciation	10,384.7	10,384.7							
6	Taxes on Income	4,067.4	4,067.4							
7	Ad Valorem Taxes	3,916.9	3,916.9							
8	Return	8,979.3	8,979.3							
9	Subtotal Revenue Requirement	27,348.3								
10	II. Steam Gen Replacement/Removal Capital Cost Subaccount									
11	Capital Expenditures - Replace	12,863.2			12,863.2					
12	Capital Expenditures - Remove	(9,319.5)			(9,319.5)					
13	Rate Base - Replace	129,013.2			129,013.2					
14	Rate Base - Remove	1,334.6			1,334.6					
15	CWIP Balance - Replace	136.6			136.6					
16	CWIP Balance - Remove	-			-					
17	Depreciation	12,888.0			12,888.0					
18	Taxes on Income	4,789.4			4,789.4					
19	Ad Valorem Taxes	495.9			495.9					
20	Return	10,949.3			10,949.3					
21	Subtotal Revenue Requirement	29,122.6								
22	III. O&M Expense Subaccount									
23	Fuel (ERRA)	1,223.0				1,223.0				
24	Fuel Carrying Costs (ERRA)	192.0				192.0				
25	Replacement Power (ERRA)	72,249.2				72,249.2				
26	Capacity Payments (ERRA)	2,915.9				2,915.9				
27	Foregone Sales Revenue (ERRA)	755.7				755.7				
28	Routine O&M	73,558.7	73,558.7							
29	Refueling (1 in 2012)	9,116.4	9,116.4							
30	Seismic Safety	831.8	831.8							
31	Investigation	17,155.3								17,155.3
32	Repairs - After Outage	6,004.2								6,004.2
33	Regulatory - After Outage	902.9								902.9
34	Defueling	166.9								166.9
35	Litigation	-								-
36	Payroll Taxes	3,744.1	3,744.1							
37	Other (Pensions, PBOP, Insurance)	31,623.9	31,623.9							
38	Subtotal	220,440.0								
39	IV. Huntington Beach Subaccount	-								

		As Reported	SCE GRC D.12-11-051	SDG&E GRC Pending	SGRP D.05-12-040	ERRA D.12-07-006 D.12-08-007 D.12-12-022	Other BA- DR Resolutions E-4502, E-4511, D. 12-14-045	Other BA - NGBA AL-2302	Transmission Owner Tariff	NEW
40	V. Demand Response Subaccount									
41	Peak Time Rebate - Small Commercial (PTRA)	-					-			
42	Demand Bidding Program (DBP 2012)	-					-			
43	Marketing, Education & Outreach (ME&O)	90.6					90.6			
44	Subtotal DR	90.6								
45	VI. Transmission Upgrades Subaccount									
46	Capital Expenditures	3,012.5							3,012.5	
47	Rate Base	-							-	
48	Depreciation	-							-	
49	Taxes on Income	-							-	
50	Ad Valorem Taxes	-							-	
51	Return	-							-	
52	Subtotal Revenue Requirement	-								
53	O&M (if any)	-							-	
54	VII. Authorized Revenue Requirement Subaccount									
55	Monthly Revenue Requirements	185.4						185.4		
56	VIII. Adders to SCE-Originated SONGS Costs									
57	SCE-Billed Costs Not Included by SCE in § III	4,274.3	4,274.3							
58	SDG&E Portion of Nuclear and Related Insurance	2,363.9		2,363.9						
59	SDG&E Portion of SONGS Site Easement	20.1		20.1						
60	SDG&E Overheads on SONGS Costs - Capital (Adder to § I)	9,983.2		9,983.2						
61	SDG&E Overheads on SONGS Costs - O&M (Adder to § III)	9,515.2		9,515.2						
62	Net Impact of Billing Lag (Temporary Adder to §§ I & III)	(3,484.4)	(3,484.4)							
63	IX. SDG&E Direct Cost of SONGS Oversight									
64	Operational and Financial Oversight Team	668.3		668.3						

NOTES

All amounts shown reflect SDG&E's actual costs for SONGS, including 20% share of SONGS 100%-level costs incurred by SCE plus contractual overheads.

SGRP costs reported net of 20% of estimated removal and disposal costs for the original steam generators granted in SDG&E's 2006 SGRP Decision D.06-11-026.

SCE advance bills SDG&E for the month and trues-up previous advance bills. The "Lag Adjustment" converts SONGS data for the billing process to match actual SDG&E posting periods.

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SDG&E's SONGS Oversight includes estimated overheads for Payroll Tax, Incentive Compensation Plan ("ICP"), Pension & Benefits, Workers' Compensation, Vacation & Sick Leave, PLPD Insurance, and Purchasing.

Property tax amounts are estimated based on an allocation of total property taxes paid.

Replacement Power (ERRA) amount estimated for 2012 excludes lost generation replacement costs for planned refueling and maintenance outage for 01/10/12 through 03/05/12 for SONGS Unit 2 of $5,039K.

Capacity Payments (ERRA) amount estimated for CPM charges and Resource Adequacy (RA) purchases.

Sunk capital line items 3-8 include SDG&E overheads and AFUDC

(End of Appendix B)

Appendix C

Timeline

Appendix C - Timeline

1/9/2012	U2 Cycle 17 (C17) refueling outage (RFO) started 60-day schedule
1/272012	U2 Fuel moved to fuel pool complete
1/31/2012	U3 leak identified
2/5/2012	U2 steam generator retainer bar problem identified
2/8/2012	SCE begins Root Cause Analysis (U3)
2/11/2012	U2 initial Eddy Current Testing (ECT) completed
2/12/2012	U3 ECT inspection locates leaking tube
2/14/2012	U2 Expanded ECT (based on U3 findings)completed
2/14/2012	U2 replace Emergency Core Cooling System mini flow piping project completed
3/1/2012	U2 fuel move from fuel pool to core completed
3/1/2012	SCE Board of Directors (BoD) meeting; Dietrich reports delay restart U2 until source of U3 tube leak known
3/2/2012	U2 High pressure Turbine retrofit project completed
3/4/2012	U2 Replacement Reactor Vessel head project completed
3/4/2012	U2 C17 RFO originally scheduled to end (Return to Service -RTS)
3/13/2012	U2 C17 RTS restart schedule change from 3/20 to 4/15 due to additional ECT
3/13/2012	U3 In-situ pressure test of 129 tubes; 8 tubes fail
3/14/2012	U2 C17 RFO restart schedule changed from 4/15 to 5/16
3/16/2012	U2 equipment hatch closed
3/19/2012	NRC onsite Augmented Inspection Team (AIT) begins ten days of inspections
3/23/2012	SCE submits Steam Generator Return-to-Service Action Plan to NRC
3/27//2012	Confirmatory Action Letter issued by NRC
3/27//2012	U2 C17 RFO restart schedule changed from 5/16 to 6/1
3/2012	SCE developed plan to postpone, cancel, and re-schedule capital projects
4/1/2012	U2 FAC project completed
4/2/2012	U2 RTS scheduled
4/3/2012	U2 equipment hatch opened
4/6/2012	U2 special interest ECT
4/10/2012	U2 Tube-to-Tube wear (TTW) discovered
4/15/2012	U3 initial ECT completed
4/20/2012	U2 TTW inspection letter to NRC
4/23/2012	U2 first tube wear Root Cause Analysis (RCA) issued by SCE
4/23/2012	U2 Emergency Diesel generator replacement project completed
4/24/2012	U2 tube plugging and stabilizing list issued
4/26/2012	SCE BoD meeting with update on SONGS: Fluid Elastic Instability cause of TTW; reports U2 restart on 6/1/12; U3 by 6/30/12
5/7/2012	U3 first tube wear RCA issued by SCE, finds TTW in U2
5/72012	U2 C17 RFO restart schedule changed from 6/1 to 7/1

5/7/2012	NRC Restart statement issued
5/16/2012	NRC issued AIT Charter rev.1
6/2012	U3 planning begins to place U3 into preservation mode
6/7/2012	U2 C17 RFO restart schedule changed from 7/1 to 8/17
6/18/2012	NRC public meeting in San Juan Capistrano (AIT Exit)
6/25/2012	Budget Review Committee meeting to defer capital projects (part 1 of 2)
7/2012	Efforts to place U3 into preservation mode begin
7/1/2012	U2 Vibration and Loose Parts Monitoring System replacement project completed
7/11/2012	Budget Review Committee meeting to defer capital projects (part 2 of 2)
7/18/2012	NRC issues initial AIT report
7/19/2012	U2 C17 RFO restart schedule changed from 8/17 to 11/18
7/27/2012	SCE separates outage response team into U2 Restart and U2/U3 long-term repair teams; SCE tells MHI of expectations of warranty conditions for long-term repair
8/23/2012	U2 C17 RFO restart schedule changed from 11/18 to 12/2
8/22/2012	NRC performs follow-up steam generator AIT inspection
8/25/2012	SCE BoD meeting with SONGS update:
9/4/2012	NRC adopted modified inspection plans for U2/U3 based on "extended Outage Shutdown Condition"
9/6/2012	SCE BoD meeting with SONGS update: status of SONGS as of 8/27 target U2 restart 12/12, U3 4Q2013
9/11/2012	U3 major systems engineering recommendations completed re long-term lay-up plan, reviews on-going; SCE-25
9/24/2012	NRC meets with Mitsubishi Heavy Industries (MHI) in Kobe, Japan
9/28/2012	NRC follow-up inspection of unresolved issues from AIT report
10/2012	SONGS-wide meeting re more inspections(TR 1056)
10/1/2012	U3 reactor defueling begins
10/3/2012	U2 CAL response submitted to the NRC re U2 restart plan
10/5/2012	U3 reactor defueling ends
10/9/2012	NRC public meeting at Dana Point
10/11/2012	MHI reps meet with Avella and Dietrich and proposed repair/replacement options; assessment expected by 2Q13 or 3Q13
10/17/2012	U2 equipment hatch closed
10/20/2012	U2 achieves Mode 4 to test systems
10/23/2012	U2 achieves Mode 3 (raised reactor coolant system to normal operating pressure and temperature to test return-to-service readiness)
10/25/2012	U2 Reactor Coolant System test at normal operating conditions (reactor not critical)
10/25/2012	SCE BoD meeting SONGS status: U2 response to CAL filed with NRC, restart discussions underway; U3 long-term repair plans in development
10/26/2012	U2 entered Mode 4
10/27/2012	U2 returned to Mode 5
11/8/2012	U2 C17 RFO restart schedule changed from 12/2 to 2/3/13

11/8/2012	E. Avella (SCE) Letter to Dr. A. Kaguchi: provides MHI with SCE's acceptable warranty conditions for long-term repair of the SGs; given in meetings since 7/27/2012; SCE-24
11/9/2012	AIT Follow-up Report : two unresolved issues from CAL; advised no reply to SCE's CAL response until inspections, technical review, public meetings, + 45 days of process time before earliest U2 restart
11/13/2012	Letter from Edward Avella to MHI Regarding Screening Criteria for Acceptance of Steam Generator Permanent Repair (SCE-20)
11/20/2012	SCE submits 1st Proof of Loss to NEAL under outage accident insurance policy (replacement power)
11/28/2012	Letter from P. Dietrich to K. Yamauchi at MHI: MHI hasn't complied with contract to provide repairs or replacements with due diligence; wants repair options for U2 and U3 by 12/28; (SCE-21)
11/30/2012	NRC public Meeting in Laguna Hills
12/3/2012	NRC conducts follow-up inspections to SCE's CAL response
12/5/2012	NRC's Atomic Safety Licensing Board held hearings to determine whether SCE needs a license amendment to restart U2 at 70%
12/13/2012	U2 C17 restart schedule changed from 2/2/13 to 3/3/2013
12/14/2012	MHI progress letters (2) to SCE on long-term repair options (Exhibits SCE-14, SCE-17)
12/14/2012	SCE submits 2nd Proof of Loss to NEAL
12/14/2012	MHI/SCE meeting for status on repair options; SCE-22
12/18/2012	NRC public meeting on requests for Additional Information (RAIs) in Washington D.C.
12/19/2012	Letter from P. Dietrich to K. Yamauchi at MHI: contract requires actual repair or replacement to occur with due diligence and dispatch; SCE-23
12/19/2012	Letter from E. Avella (SCE) to Dr. H. Kaguchi at SONGS SG Repair Site Team: follow-up to 12/14 meeting, MHI should provide 3 options, following SCE review criteria—MHI missed two prior dates for final recs
12/20/2012	MHI provided long-term repair options and recommendations (SCE-15)
12/20/2012	SCE submits 3rd Proof of Loss to NEAL; total of claims is $234 million (100%), $183 million (SCE share)
12/26/2012	NRC request for additional information in response to CAL
12/29/2012	MHI Letter to SCE
2013	
1/30/2013	U3 Long term preservation Plan Rev. 8; SCE-25

(End of Appendix C)

Appendix D

O&M by Functional Group

Appendix D – O&M by Functional Group

Functional Group		Preliminarily Allowed	Total Base Recorded	Recorded Base-Routine	Difference between Preliminarily Allowed and Recorded Base-Routine	SCE Claimed Exempt[1] ($ / %)	Comments
		All values in 1000s of 2012$, 100% Share					
Operations	Labor	$31,654	$39,437	$34,373	$(2,719)	$10,657 / 30%	Responsible for operation of SONGS, including safety systems, in normal or shutdown conditions.
	Non-Labor	$3,704	$1,385	$1,385	$2,319		
	Total	$35,358	$40,822	$35,758	$(400)		
Maintenance	Labor	$64,401	$52,518	$51,409	$12,992	$33,025 / 30%	Performs preventive and corrective maintenance and testing of mechanical, electrical, control, and protective systems.
	Non-Labor	$45,584	$36,745	$36,745	$8,839		
	Total	$109,985	$89,263	$88,154	$21,831		
Engineering	Labor	$41,984	$40,049	$37,758	$4,226	$7,923 / 15%	Of the five divisions within this group, SCE asserts that three divisions (Plant Engineering, Nuclear Safety, and Nuclear Oversight/Assessment) are essential during shutdown.
	Non-Labor	$10,653	$(1,257)	$(1,257)	$11,910		
	Total	$52,637	$38,792	$36,502	$16,136		
Site Projects	Labor	$852	$657	$657	$196	$0 / 0%	Performs cyclical or reactive projects. SCE does not contend that expenses in this group would be necessary under extended shutdown conditions.
	Non-Labor	$14,876	$16,896	$16,896	$(2,020)		
	Total	$15,728	$17,553	$17,553	$(1,825)		
Rad Chemical	Labor	$15,770	$12,835	$11,828	$3,942	$7,238 /	Responsible for chemistry control of

[1] Converted from 2009$ as shown in Table V-4 of SCE-1 by multiplying by 1.095

Functional Group		Preliminarily Allowed	Total Base Recorded	Recorded Base-Routine	Difference between Preliminarily Allowed and Recorded Base-Routine	SCE Claimed Exempt[1] ($ / %)	Comments
Control	Non-Labor	$8,314	$7,624	$7,624	$690	30%	fuel pools and effluent as well as radioactive material control.
	Total	$24,084	$20,459	$19,452	$4,632		
Regulatory Affairs	Labor	$8,917	$9,316	$9,112	$(195)	$9,591 / 75%	Includes emergency preparedness and occupational safety and health.
	Non-Labor	$3,843	$1,714	$1,714	$2,129		
	Total	$12,760	$11,030	$10,825	$1,935		
Security	Labor	$39,870	$41,601	$41,326	$(1,456)	$37,357 / 90%	Protection against radiological sabotage per NRC regulations.
	Non-Labor	$1,410	$2,112	$2,112	$(702)		
	Total	$41,280	$43,713	$43,438	$(2,158)		
Training	Labor	$10,670	$10,963	$10,942	$(272)	$4,427 / 30%	Trains operations, maintenance, and other staff.
	Non-Labor	$4,049	$2,619	$2,619	$1,430		
	Total	$4,719	$13,582	$13,561	$1,158		
Nuclear Support	Labor	$31,239	$30,646	$29,762	$1,477	$17,879 / 20%	Implements financial planning, budgeting, accounting, and compliance programs.
	Non-Labor	$58,328	$52,743	$52,743	$5,585		
	Total	$89,567	$83,389	$82,506	$7,061		
Corporate Support	Labor	$(10,688)	$0	$0	$(10,688)	n/a	
	Non-Labor	$(7,032)	$(20,463)	$(20,463)	$13,431		
	Total	$(17,720)	$(20,463)	$(20,463)	$2,743		
Total	Labor	$234,669	$238,021	$227,165	$7,504	$128,096 / 32%	
	Non-Labor	$143,729	$100,118	$100,118	$43,611		
	Total	$378,398	$338,139	$327,284	$51,114		

(End of Appendix D)

Appendix E

SONGS 2012 Base O&M Costs Excluding Corporate Support, Severance, and IT (100% share, 000's of 2012$

Appendix E – SONGS 2012 Base O&M Costs, excluding Corporate Support, Severance, and IT (100% share, 000's of 2012$)

Month	Base - Routine				SGIR (includes both "Base" and "Total" SGIR)				Total Adopted Base O&M
	Recorded[1]	Adjustment Factor	Adopted	Disallowed	Recorded[2]	Adjustment Factor	Adopted as Base O&M	To Review in Phase 3[3]	
January	35,354	1.0	35,354	0	0	1.0	0	0	35,354
February	33,788	1.0	33,788	0	9,246	1.0	9,246	0	43,034
March	29,112	1.0	29,112	0	18,214	0.5	9,107	9,107	38,219
April	29,556	1.0	29,556	0	20,970	0.0	0	20,970	29,556
May	29,135	1.0	29,135	0	7,832	0.0	0	7,832	29,135
June	25,770	0.9	23,193	2,577	10,092	0.0	0	10,092	23,193
July	28,294	0.8	22,635	5,659	13,603	0.0	0	13,603	22,635
August	27,222	0.7	19,055	8,167	30,171	0.0	0	30,171	19,055
September	23,483	0.6	14,090	9,393	20,471	0.0	0	20,471	14,090
October	35,353	0.5	17,677	17,677	2,007	0.0	0	2,007	17,677
November	25,515	0.4	10,206	15,309	3,794	0.0	0	3,794	10,206
December	25,164	0.4	10,066	15,098	4,556	0.0	0	4,556	10,066
Total	347,746	n/a	273,867	73,880	140,956	n/a	18,353	122,603	292,220

(End of Appendix E)

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[1] SCE-35 at 6.

[2] Ibid. Sum of lines: "Total Base – SGIR Recorded" and "Total SG Insp & Repair Recorded."

[3] If, in Phase 3, SCE is found to have been imprudent or otherwise at fault, these SGIR costs may be subject to refund.

Appendix F

Capital Expenditures

Appendix F – Capital Expenditures

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
Common - Required	Total	$38,389	Includes projects that are not unique to a single reactor unit.
	Spare Parts Blanket	$4,182	Includes long lead time items needed for continuity of service that are not typically used more than once a year.
	Outage Replacements - overhauls to SONGS 2C17 Allowance	$5,377	Replacements of in-kind capital equipment during the U2 Refueling Outage (RFO)
	U2/3 ISFSI AHSMs	$4,819	New Advanced Horizontal Storage Modules (AHSMs) are added to the Independent Spent Fuel Storage Installation (ISFSI) for each refueling. The AHSMs protect the fuel canisters and provide radiation protection.
	SCR 32PTH System - Canister	$5,223	This project is an upgrade of the dry storage fuel canisters to hold more fuel per canister. The project also includes purchase of related equipment.
	U2/3 Dry Cask Spent Fuel Storage - Canisters	$11,281	Transfer of fuel from the ISFSI to dry storage for the U2 RFO and U3 defueling.
	Other (furniture, computers, tools, transfer of fuel to ISFSI)	$7,507	
Work in Progress	Total	$84,533	Includes projects that were in process during 2011.
	Control Room Upgrade	$3,545	Changes to the Control Room to meet industry standards and NRC expectations.
	Eddy Current Testing U2C17	$3,851	The NRC requires a full length examination of each steam generator tube after the first cycle of operation.
	CCW Heat Exchangers SONGS 2	$5,017	The Component Cooling Water (CCW) heat exchangers for U2 were replaced during the RFO.

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
	U2 High Pressure Turbine (HPT) Retrofit	$7,075	The U2 HPT was replaced during the RFO. This project was approved by the CPUC in SCE's 2009 GRC, D.09-03-025.
	Replace 400' of U2 ECCS Schedule 10 Mini Flow Piping	$7,629	During the U2 Cycle 16 RFO, evidence of damage to the Emergency Core Cooling Schedule (ECCS) 10 piping was discovered. During the U2 Cycle 17 RFO in 2012, the highest risk sections of piping were replaced.
	FAC - Capital R2C17	$7,658	This is part of a long-term project to replace piping components subject to Flow Accelerated Corrosion (FAC). The costs shown here were incurred during the U2 Cycle 17 RFO. Replacements for U3 were rescheduled.
	U2 Rapid Refueling	$10,840	Completed during the U2 Cycle 17 RFO, this project was designed to allow faster assembly and disassembly of the Reactor Vessel Heads (RVH).
	U2 Procure & Install RRVH Heads	$29,069	Replacement of the RVH during the U2 Cycle 17 RFO.
	Other (Tech Specs, various capital replacements)	$9,849	
Emergent - Regulatory Required	Total	$17,937	Projects that emerged after SCE's 2012 GRC forecast due to regulatory requirements.
	Cyber Security Phase 2	$3,576	Phase 2 (of 3) of an NRC-required project to implement a cyber security defense strategy.
	NFPA-805 Fire	$4,494	An ongoing project to meet NRC fire protection requirements that apply regardless of the operational status of the plant.
	Other (upgrades related to Once Through Cooling environmental, Fukushima	$9,867	

Category	Projects	2012 Recorded Expenditures (1000s, nominal, 100% share)	Comments
	responses, and security)		
Rescheduled	Total	$1,434	Projects that were started in 2012, but rescheduled or suspended after the outage began.
Ongoing - Completion Rescheduled	Total	$19,754	Projects started before 2012, but rescheduled or suspended due to the outages. Includes some projects for U3 that are analogous to U2 projects described in the "Works in Progress" category.
	U3 HPT Retrofit Project	$8,963	Analogous to the U2 project above, but not completed.
	Other (CCW Heat Exchangers, Rapid Refueling and RVHs, U2 water purification)	$10,791	
Marine Mitigation	Total	$5,559	Ongoing projects to comply with SONGS's permit from the California Coastal Commission.
	Reef	$1,388	Costs associated with Coastal Commission monitoring of the completed reef.
	Wetlands	$4,171	Monitoring of the restored wetlands and corrective construction.
Grand Total		**$167,606**	

(End of Appendix F)

Appendix G

Results of Operations Model Output From SCE's GRC

Appendix G – Results of Operations Model Output, from SCE's 2012 GRC

Line	Item	Adopted (1000s of dollars)	
1.	**TOTAL OPERATING REVENUES**	5,596,526	
2.	**OPERATING EXPENSES:**		
3.	Production		
4.	Steam	14,478	
5.	Nuclear	298,447	
6.	Hydro	56,000	
7.	Other	126,328	
8.	Subtotal Production	495,253	
9.	Transmission	87,740	
10.	Distribution	465,850	
11.	Customer Accounts	209,595	
12.	Uncollectibles	11,062	
13.	Customer Service & Information	45,521	
14.	Administrative & General	818,289	
15.	Franchise Requirements	49,381	
16.	Revenue Credits	(149,965)	
17.	Subtotal	2,032,725	
17.	Escalation	168,852	
18.	Depreciation	1,221,584	
19.	Taxes Other Than On Income	245,929	
20.	Taxes Based On Income	463,520	
21.	Total Taxes	709,449	
22.	**TOTAL OPERATING EXPENSES**	4,132,609	
23.	**NET OPERATING REVENUE**	1,316,581	
24.	**RATE BASE**	15,063,859	
25.	**RATE OF RETURN**		8.74%
26.	Four Corners	88,388	
27.	Mohave	(5,552)	
28.	Legacy Meters	64,500	
29.	**REVENUES AT PRESENT RATES**	5,398,840	
30.	**NET INCREASE OVER PRESENT RATES**		197,686

(End of Appendix G)

BRIEFING ON SAN ONFRE NUCLEAR GENERATING STATION OII
PHASE 1 AND PHASE 1A DECISION
(from ALJs Darling and Dudney)

- The Phase 1/1A decision adopts interim rate reductions for Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) ratepayers as a result of reduced operating costs in 2012 following a Unit 3 steam generator tube leak at San Onofre Nuclear Generating Station (SONGS) on January 31, 2012 and an immediate halt to generation.
- The decision orders refunds of approximately $94 million ($74.2 million SCE; $19.3 million SDG&E) applicable only to the 2012 revenue requirement.
- The U.S. Nuclear Regulatory Commission (NRC) found that SCE appropriately responded to the tube leak by shutting down Unit 3, and took reasonable steps to investigate the steam generator problems and to mitigate some costs. However, as the year progressed, we found SCE to be single-minded about its restart plan, and slow to understand the technical challenges and regulatory timeframe required to implement it.
- The decision establishes a timeline of significant events and imputes to SCE what it knew or should have known about the status of both units during 2012.
- In January and February, SCE was conducting a scheduled refueling outage (RFO) on Unit 2; Unit 2 did not return to service. Prior to March 15, SCE acted as a reasonable operator to complete the RFO, and try to determine the causes and extent of the damage to both Unit 2 and Unit 3. These costs are recoverable.
- As of March 15, SCE knew that Unit 3 had an unknown type of tube wear which led to the leak, and Unit 2 was of similar design. On March 27, 2012, the NRC prohibited any restart until numerous conditions were met, and cleared by the NRC. By May 7, 2013, SCE knew that both Unit2 and Unit 3 had the unknown Tube-to-Tube wear phenomena and that repair options were undeveloped.
- The Commission finds SCE's decisions after May 2012 to apply resources to a restart plan was the result of an unsound decisionmaking process, primarily because SCE did not consider cost or other options, or realistically assess the regulatory hurdles blocking a reasonably foreseeable restart. Therefore, the decision adopts interim rate reductions using a gradual percentage disallowance of O&M beginning in June 2012, and continuing through the end of 2012.
- SONGS-related O&M is separated into "Base (routine)" and Steam Generator Inspection and Repair (SGIR) costs resulting from the outages. About 21% of Base O&M was disallowed in this decision. SGIR costs are not allowed, but will be considered in the context of all costs of the Steam Generator Replacement Project in Phase 3.

- About 80% of recorded 2012 capital expenditures are found to be reasonable, including those necessary to maintain the plant in safe condition, compliant with all applicable regulations.
- Recorded capital-related costs exceeded GRC estimates for both utilities. We reduced capital additions by 20% to remove unnecessary additions, but reductions to rate base result in an increase to rates, due to effects of the Tax Relief Act of 2010 that provided bonus depreciation for some assets recorded in 2012.
- The decision adopts a method for calculating the cost of replacement power in 2012, recovery of replacement power costs will be determined in Phase 3.
- The 2012 rate adjustments and the resulting 2012 revenue requirement reduction are summarized below:

Summary of Adopted Ratemaking			
100% share, 000s of 2012$			
Cost Category	**Adopted**	**Refund in 2014 Rates**	**Review in Phase 3**
Base O&M	$273,867	$73,880	
SGIR O&M	$18,353		$122,603
Other O&M (Corp. Support, IT, Severance)	$1,663	$4,527	
Subtotal	$293,883	$78,407	$122,603
RFO O&M	$45,077		
Seismic	$4,077		
Capital Expenditures	$134,080		
Capital Additions	($33,520)	($500)	
Replacement Power			To be calculated
2012 Revenue Requirement due to O&M and Capital Adjustments		($93,522) SCE: ($74,222) SDG&E: ($19,300)	

- The Utilities are ordered to make the refunds through each utility's established base rate balancing mechanism, effective on January 1, 2014. For SGIR costs already recovered in rates, the funds shall be separately accounted for and interest accrued at the one-year Treasury rate for the benefit of ratepayers in the event the Commission later finds these revenues should also be refunded.

SONGS PD – Comments Summary

Proceeding I.12-10-013

(prepared by Charlyn Hook)

SCE

Legal issue raised by other parties: SCE says Commission should use the preponderance of evidence standard (which just means more likely than not), not a higher "clear and convincing evidence" standard as some parties (ORA and World Business Academy) have argued.

SCE says that it wasn't clear that Unit 2 was going to have the same TTW problems as Unit 3 until April and May, when more sensitive testing was done. So we cannot impute knowledge to them back in March 2012.

SCE argues parties incorrect in arguing that there should be no costs allowed for Unit 2 because a) it was reasonably pursuing the 70% restart plan for Unit 2, and b) even if it had put Unit 2 in preservation mode sooner, it still would have been required to maintain a certain level of staffing for safety and general NRC requirements, thus they argue there is no evidence that they could have saved costs. SCE maintains the record needs to be re-opened to look at this issue more.

SCE argues that labor related A&G (benefits, incentive compensation) is reflected in the PD's disallowance of some O&M costs. SCE disagrees with ORA's argument that the disallowance should be even greater, because non-labor related A&G costs should be added into the disallowance, as these costs could not have been avoided even if SCE had reduced staffing at SONGS.

SCE disputes A4NR's allegation that SCE did not produce all correspondence between SCE and Mitsubishi; SCE says it produced some correspondence and never claimed it produced all communications.

SDG&E

SDG&E argues that on the one hand, the PD states that there has been no finding of imprudence, but yet also states that SCE's decision to pursue the restart of Unit 2 was the product of unsound decisionmaking and imputes (a share) of this to SDG&E. SDG&E argues that this may prejudge the outcome of some Phase 3 issues.

SDG&E is arguing that it should not be allocated its share of the disallowance, now, and that this should be deferred until Phase 3.

Supports preponderance of evidence standard.

PD need to clarify the derivation of the 20% reduction, and that it reflects only "capital spent in 2012 after May 7, 2013, that actually closed to ratebase in 2012."

<u>TURN</u>

TURN largely supports the PD and finds the May 7th date as the date to begin O&M reductions to be reasonable.

With respect to the Steam Generator Inspection and Repair (SGIR), the PD defers consideration of the reasonableness of these costs to Phase 3. The PD states that "we have made no finding that SCE was at fault or imprudently managed the steam generator replacement project, or unreasonably incurred the incremental SGIR costs in 2012." (PD p. 50) and orders SCE and SDG&E to "cease collection of these incremental costs" in rates. (PD p. 5) TURN questions what incremental costs are being incurred, and argues that all 2012 SGIR expenditures should be credited to ratepayers as an offset in 2014 rates. If Phase 3 concludes that these costs are reasonable, SCE and SDG&E can seek rate recovery.

Phase 3 scope/clarification: TURN recommends that the PD should clarify that if SCE is found to have imprudently managed the SGRP, costs should be disallowed in the Phase 3. TURN also concerned about statements in the PD to the effect that SCE can be found imprudent for SGIR costs if they had pre-existing knowledge of the risks of failure; they think this is too limiting.

TURN questions statement in the PD that the SGRP costs are presumed reasonable if under the original forecast in D.05-12-040.

Construction Work in Progress (CWIP): The PD should not prejudge the issue of whether accrued AFUDC for SONGS related CWIP can be capitalized or recovered. This is a Phase 2 issue, but TURN doesn't want it pre-judged in this PD and recommends a few modifications to the PD.

Replacement Power Cost Calculation: Supports the definition of replacement power costs in the PD. Supports the PD's direction to the utilities to recalculate the costs based on different indexes for replacement energy and forgone sales, and urges that the PD clarify that IOUs must use hourly DLAP prices, and make no other changes to this section.

ORA

The PD's findings are supported by a complete record, case doesn't need to be reopened. This will just delay the refund to ratepayers. O&M cost reductions should begin as of March 15, 2012, and the record supports this conclusion.

Disagrees with SCE's argument that it couldn't have avoided additional capital expenditures by putting Unit 2 in preservation mode sooner. Agrees with the PD that SCE knew or should have known by March 15 2012 that the potential design defect was present in both units.

SDG&E is part owner of SONGS, and thus the PD's allocation of the 20% share of the disallowance in its SONGS is reasonable; the PD does not impute SCE's actions as owner to SDG&E.

Additional A&G costs should be included in the disallowance. Doesn't quantify the amount, but says the O&M (10% per month) "ramp down" mechanism in the PD should also be applied to A&G costs.

Disagrees with SCE's comment that it should be able to argue in Phase 3 that some portions of the power replacement costs should not be subject to disallowance; SCE should not be able to reserve this argument for the future.

Coalition to Decommission San Onofre

Supports PD but thinks the amount of the refund is overly conservative based upon the record cited in the PD. Advocates an 80% Base O&M disallowance for June-December 2012; and disallow 20% of the refueling for Unit 2 (PD approves the whole thing), and disallow 56% of Cap X (PD cuts by 20%).

Some comments re emergency planning , coordination with state and local governments and public education.

WEM

One issue: WEM believes that SCE misused community outreach funds to promote SONGS/convince community that it was clean safe and affordable. The PD acknowledges that some of SCE's materials have a self-serving component.

World Business Academy

PD should use clear and convincing evidence standard of review because this is not a standard GRC, it is a "specialized proceeding."

PD FOF 10 states that on March 15, SCE knew or should have known that the TTW problem was a potential design defect in both units 2 and 3. PD p. 3, FOF 18 and COL 2 and 3 state that by May 7th, SCE knew or should have known that TTW problem in Unit 3 was also present in Unit 2. So, they question why May 7th was used as the date for the O&M disallowance, and not March 15. They say that March 15 should be the relevant non-recovery date.

The 20% reduction for capital expenses applied in the PD is not supported by substantial evidence, and is based on SCE's testimony which is not reliable.

Chinese American Institute for Empowerment, Black Church Group, Latino Business Council, et al. (Coalition representing minority groups)

They believe that "this proceeding should not be used to permanently end nuclear power as a potentially effective and safe alternative to fossil fuels." Have to consider the financial implications and California's clean energy goals before banning any one resource, and this reflects the views of the minority population.

Coalition of California Utility Employees (CCCUE)

One issue: disagrees with PD's conclusion that SCE was unreasonable in maintaining full staff after May 2012. CUE argues these are highly trained workers that would have been needed if they restarted the facility.

SONGS OII I.12-10-013 **January 16th Agenda Item __**

Proposed Decision on Phase 1 Regarding 2012 SONGS-Related Expenses and Expenditures (Florio/Darling/Dudney)

(Summary prepared by Charlyn Hook)

This Phase 1 decision is focused on the reasonableness of the 2012 expenditures and how SCE responded to the tube wear problems discovered in January 2012 on the steam generators in Units 2 and 3.

I. Basic Info:

SONGS All Party: Jan 15th 1:30 pm.

SONGS is jointly owned by SCE (78%), SDG&E (20%) and the City of Riverside (2%). The numbers in the PD are talking about the total share for the two CPUC-jurisdictional utilities.

Both Units 2 and 3 have been non-operational since Jan. 2012.

When operational, SONGS provided approx. 2200 MW of base load power, and voltage support to the LA area.

The NRC has safety and regulatory jurisdiction over SONGS; we have jurisdiction over rates.

Acronyms:

2 similar acronyms used in the PD – not the same thing:

Steam Generator Replacement Project (SGRP)

Steam Generator Inspection and Repair or (SGIR). (see explained below in the phases overview.)

II. Overview of Phases of SONGS OII:

There are 3 phases to the SONGS OII

Phase 1: scope includes determining the reasonableness of SONGS-related expenditures in 2012; these costs include removal of fuel from Unit 3, operating and maintenance costs (this broken down in PD into Base O&M and Steam Generator Inspection and Repair or **"SGIR"** O&M), community outreach and emergency preparedness, and if any of the rates preliminarily approved in the 2012 GRC should be refunded. The SONGS outage occurred during the pendency of the SDG&E and SCE

GRC's; 2012 costs were approved in the GRCs, subject to refund, and a memo account (the SONGSMA) was established in both cases.

<u>Phase 1A</u>: is to determine a methodology for approximating replacement power costs necessitated by the SONGS outage. (this was going to be a separate PD, but they rolled it into Phase 1.)

<u>Phase 2</u>: this phase designed to deal with whether and when the SONGS plant and O&M should be removed from ratebase going forward since the plant is no longer in service; evidentiary hearings were held on this last year, and a PD is coming.

<u>Phase 3</u>: this phase will look at the causes of the steam generator damage and allocation of responsibility. (Mitsubishi Heavy Industries (MHI) is the manufacturer and/or designer of the tubes that caused damage.) While Phase 1 is limited to 2012 costs (including the SGIR O&M costs), Phase 3 will looks at the utilities two applications for recovery of costs related to the Steam Generator Replacement Project (**SGRP**). The Commission approved the SGRP in a 2005 decision (D.05-12-040); the Commission authorized up to $680 million (2004 dollars) for removal and replacement of the steam generators in units 2 and 3; the utilities filed applications in 2013 to recover the actual amounts spent on the SGRP. SCE's application indicated it spent $768.5 million (nominal dollars).

<u>III. Summary of the Phase 1 PD:</u>

This Phase 1 PD does two things: (1) adopts an interim rate reduction for SCE and SDG&E ratepayers for 2012 operating costs; and (2) determines a methodology to be applied going forward for assessing the replacement power costs.

The PD looks mainly at how SCE responded to the discovery of the problems with the tubes in the steam generators in 2012. The crux of the PD is an assessment of what point in the Spring of 2012 that SCE knew enough about the causes and conditions of the Tube to Wear (TTW) problems in its steam generators on Units 2 and 3, to know that it would not be economically viable to continue operating these units and incurring O&M costs. The PD's reasoning is factually based on the timeline of events; there is a full timeline in Appendix C to the PD, so I will highlight only a few key dates below.

<u>A. Ratepayer Refund for 2012 (Phase 1)</u>

The PD establishes refunds due to customers for 2012 costs deemed unreasonable in the PD.

Summary of Refund (summary table in PD p. 97)

Summary of Adopted Ratemaking
100% share, 000s of 2012$

Cost Category	Adopted	Refund in 2014 Rates	Review in Phase 3
Base O&M	$273,867	$73,880	
SGIR O&M	$18,353		$122,603
Other O&M (Corp. Support, IT, Severance)	$1,663	$4,527	
Subtotal	$293,883	$78,407	$122,603
RFO O&M	$45,077		
Seismic	$4,077		
Capital Expenditures	$134,080		
Capital Additions	($33,520)	($500)	
Replacement Power			To be calculated
2012 Revenue Requirement due to O&M and Capital Adjustments		($93,522) SCE: ($74,222) SDG&E: ($19,300	

The disallowance for Base O&M of $73,880 represents about a 21% disallowance. For Capital Expenditures, the $134,080 disallowance is also about 20%. However, the PD explains that it does not result in a rate reduction due to the resulting inability to claim bonus depreciation under the Tax Relief Act of 2010.

*SGIR O&M – Considered in Phase 3; no refund at this time, total amount at stake is $122,603, and costs must continue to be tracked in a memo account. Phase 3 will also consider the possibility that SCE will recover some proceeds Mitsubishi (MHI) the tube manufacturer, or from insurance.

Timeline/Reasoning of PD:

Jan. 10 2012	SONGS Unit 2 scheduled for an outage for refueling. (referred to as the RFO). The initial plan was to have Unit 2 back online by March 5th.
Jan. 31 2012	Unit 3 taken off line due to a tube leak problem.
Spring 2012	SCE investigated the causes of the Tube to Wear (TTW) problems in the steam generators, MCI undertakes a root cause analysis. NRC informs SCE that it cannot re-start units 2 and 3 without NRC approval.
Pre-March 15 2012	PD reasons that up to March 15, SCE acted as a reasonable operator. Therefore, SCE can recover Steam Generator

	Inspection and Repair (SGIR) costs necessary for ordinary operations up to this point in time.
Post-March 15 2012	PD reasons that SCE knew of design defects and the TTW problems on both Unit 2 and 3; the problems were discovered on Unit 3, but Unit 2 is similar (possibly identical) in design. Therefore, SCE's Steam Generator Base Inspection and Repair (SGIR) O&M costs may be subject to further review/refund in Phase 3. The Commission approved the SGRP program in 2005, so reasonable rate recovery is authorized. The risks of the SGRP program as a whole will be looked at in Phase 3.
April 2012	SCE provided the Commission with a root cause analysis report on the TTW problem. Therefore, SCE definitely knew it had serious problems by April 2012.
April 26, 2012	PD states that SCE unrealistically advised its Board that Units 2 and 3 would return to service by June of 2012, despite the fact that they needed NRC approval.
May 7, 2012	PD reasons SCE's decisions to continue spending on the restart of Units 2 and 3 were not reasonable, because they did not consider the costs, and regulatory obstacles of restarting the units. PD states that by this date, SCE knew or should have known that Unit 2 may not restart, but was "singularly focused on the restart option." (p. 36.)
June 2012	SCE was planning to put Unit 3 in preservation mode, therefore it should have known that Unit 2 was similarly situated. By June 7 – SCE announces that it would not restart Units 2 and 3 and would seek decommissioning approval. Therefore, the PD implements a gradual disallowance of O&M costs. (10% per month) for June through December 2012.

B. Replacement Power Costs Methodology (Phase 1A).

A methodology for calculating the approximate cost of replacement energy and capacity costs necessitated by the outage of SONGS. All parties agree that these costs can only be approximated, because we can't ever know what the market price would have been if the outage did not happen.

The PD adopts a methodology for calculating the power costs, but these costs won't be determined until Phase 3.

The PD defines replacement costs as the net increase in cost to the utility to meet its energy and capacity needs for bundled customers. This definition includes consideration of cost of replacement generation, revenues from sales, capacity, DR costs, onsite load, some Congestion Revenue Right related costs, but not EE costs. (Much more detail in the PD.)

Basic formula: Quantity (net short/long position) x Price ($ MWh) = Hourly Replacement Energy Cost (or Forgone Sales).

Apart from agreeing that any formula is an approximation, the parties differed greatly in what the methodology should be, and there is a thorough discussion in the PD of the parties's proposals.

IV. Other Parties' Positions

The PD indicates that **TURN and ORA** are taking a more extreme position on the disallowance. They argue that SCE should recover no capital costs after January 31, 2012, when both units were offline. They argue there should be no SGIR costs, no O&M costs for 2012 have been proven reasonable. DRA would only agree that some safety-related costs should be allowed.

The PD finds that ORA's approach is "too blunt" because SCE did not know by Jan. 31 that both units would never return to service.

<u>SCE – Dec. 9th meeting handout</u>. 3 main points:

1. The PD wrongly criticizes SCE for working to restart Unit 2. SCE says it was working on the 70% restart plan for Unit 2, that it expected the NRC to approve this in about 60 days (this may have been optimistic), and also that it wasn't clear from the scoping memo that they were going to have to litigate this issue, and the record is unclear on this point in their view. They request that the PD be withdrawn and the record re-opened to further evaluate the issue of SCE's reasonableness in pursuing the re-start of Unit 2 issue.

2. The PD wrongly criticizes SCE for failing to put Unit 2 in preservation mode and reduce staffing after May 2012. They say it wasn't feasible to lay people off not knowing the future status of the unit's return to service.

3. With respect to the replacement power cost methodology, the PD should not prejudge policy questions of which categories of market-related costs should be disallowed if imprudence is found in Phase 3. The PD should be clarified that to indicate that parties may advocate that some market costs should NOT be disallowed.

Tab 7

_

From: McCarthy, Ryan@ARB <rmccarth@arb.ca.gov>
Sent: Tuesday, February 18, 2014 5:24 PM
To: Weisenmiller, Robert@Energy; michael.picker@cpuc.ca.gov
Cc: Rechtschaffen, Cliff; Nichols, Mary D. @ARB
Subject: RE: March 4th EP meeting: SONGS update?

Resending with Michael's correct email address.

From: McCarthy, Ryan@ARB
Sent: Tuesday, February 18, 2014 5:20 PM
To: Weisenmiller, Robert@Energy; 'Michael.picker@cpuc.ca.gov.'
Cc: Cliff.Rechtschaffen@GOV.CA.GOV; Nichols, Mary D. @ARB
Subject: March 4th EP meeting: SONGS update?

Hi all,

It looks like we're go for a March 4th Energy Principals meeting. Meeting with the renewables stakeholders, long overdue, will be on the agenda. I'm wondering if you want to do the SONGS deep dive, as well, or give it more time at a later meeting? I expect that we'll be probably be hour-and-a-half in meeting with the renewables folks, getting settled, background discussions, etc.. Would another hour or hour-and-a-half be sufficient for SONGS?

Thanks,
Ryan

Ryan McCarthy, PhD
Science and Technology Policy Advisor
Office of the Chair
California Air Resources Board
(916) 323-2602 (office)
(916) 217-4714 (cell)

Tab 8

Message

From: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
Sent: 2/18/2014 5:26:16 PM
To: McCarthy, Ryan@ARB [rmccarth@arb.ca.gov]
CC: Michael.picker@cpuc.ca.gov. [Michael.picker@cpuc.ca.gov]; Rechtschaffen, Cliff [cliff.rechtschaffen@gov.ca.gov]; Nichols, Mary D. @ARB [mnichols@arb.ca.gov]; Rossi, Michael@HSR [rossim@aol.com]
Subject: Re: March 4th EP meeting: SONGS update?

Songs meeting has to happen now. Will be polite to renewables but ... Bob

Sent from my iPhone

On Feb 18, 2014, at 5:20 PM, "McCarthy, Ryan@ARB" <rmccarth@arb.ca.gov> wrote:

> Hi all,
>
> It looks like we're go for a March 4th Energy Principals meeting. Meeting with the renewables stakeholders, long overdue, will be on the agenda. I'm wondering if you want to do the SONGS deep dive, as well, or give it more time at a later meeting? I expect that we'll be probably be hour-and-a-half in meeting with the renewables folks, getting settled, background discussions, etc.. Would another hour or hour-and-a-half be sufficient for SONGS?
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> Ryan McCarthy, PhD
> Science and Technology Policy Advisor
> Office of the Chair
> California Air Resources Board
> (916) 323-2602 (office)
> (916) 217-4714 (cell)

Tab 9

Message

From: McCarthy, Ryan@ARB [rmccarth@arb.ca.gov]
Sent: 2/18/2014 5:34:15 PM
To: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
CC: Michael.picker@cpuc.ca.gov. [Michael.picker@cpuc.ca.gov]; Rechtschaffen, Cliff [cliff.rechtschaffen@gov.ca.gov]; Nichols, Mary D. @ARB [mnichols@arb.ca.gov]; Rossi, Michael@HSR [rossim@aol.com]
Subject: Re: March 4th EP meeting: SONGS update?

Maybe we can push renewables meeting to 1:15, get them out by 2, and talk SONGS for an hour or two afterwards?

Sent from my iPhone

On Feb 18, 2014, at 5:26 PM, "Weisenmiller, Robert@Energy" <Robert.Weisenmiller@energy.ca.gov> wrote:

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>> Ryan McCarthy, PhD
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>> California Air Resources Board
>> (916) 323-2602 (office)
>> (916) 217-4714 (cell)

Tab 10

From: Picker, Michael <Michael.Picker@cpuc.ca.gov>
Sent: Tuesday, February 18, 2014 5:40 PM
To: McCarthy, Ryan@ARB
Subject: RE: March 4th EP meeting: SONGS update?

Yes.

Sent from my Verizon Wireless 4G LTE smartphone

-------- Original message --------
From: "McCarthy, Ryan@ARB"
Date:02/18/2014 5:34 PM (GMT-08:00)
To: "Weisenmiller, Robert@Energy"
Cc: "Picker, Michael" ,"Rechtschaffen, Cliff" ,"Nichols, Mary D. @ARB" ,"Rossi, Michael@HSR"
Subject: Re: March 4th EP meeting: SONGS update?

Maybe we can push renewables meeting to 1:15, get them out by 2, and talk SONGS for an hour or two afterwards?

Sent from my iPhone

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>> (916) 323-2602 (office)
>> (916) 217-4714 (cell)

Tab 14

Message

From: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Sent: 2/18/2014 9:05:08 PM
To: PMP Kristen Kelley [kkelley@caiso.com]
Subject: Fwd: March 4th EP meeting: SONGS update?

I think that March 4 is our likely new date. Note the discussion about priorities.

Michael Picker

Redacted

Begin forwarded message:

> **From:** "Weisenmiller, Robert@Energy" <Robert.Weisenmiller@energy.ca.gov>
> **Date:** February 18, 2014 9:00:36 PM PST
> **To:** "Rossi, Michael@HSR" <rossim@aol.com>
> **Cc:** "McCarthy, Ryan@ARB" <rmccarth@arb.ca.gov>, "Michael.picker@cpuc.ca.gov." <Michael.picker@cpuc.ca.gov>, "Rechtschaffen, Cliff" <cliff.rechtschaffen@gov.ca.gov>, "Nichols, Mary D. @ARB" <mnichols@arb.ca.gov>
> **Subject: Re: March 4th EP meeting: SONGS update?**
>
> Ditto.
>
> Sent from my iPhone
>
> On Feb 18, 2014, at 8:37 PM, "rossim@aol.com" <rossim@aol.com> wrote:
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>> Works for me.
>>
>> Sent from my iPhone
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>>> Sent from my iPhone
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Thanks,

Ryan

Ryan McCarthy, PhD

Science and Technology Policy Advisor

Office of the Chair

California Air Resources Board

(916) 323-2602 (office)

Redacted (cell)

<winmail.dat>

Tab 15

Message

From: Nichols, Mary D. @ARB [mnichols@arb.ca.gov]
Sent: 2/18/2014 9:23:23 PM
To: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
CC: Rossi, Michael@HSR [rossim@aol.com]; McCarthy, Ryan@ARB [rmccarth@arb.ca.gov]; Michael.picker@cpuc.ca.gov. [Michael.picker@cpuc.ca.gov]; Rechtschaffen, Cliff [cliff.rechtschaffen@gov.ca.gov]
Subject: Re: March 4th EP meeting: SONGS update?

Meeting with renewables industry is a box we need to check
But it does not need to be just those who signed the letter to the Governor. If you have names of individuals/companies that should be included, please forward ASAP so we can get them invited.

Sent from my iPhone

> On Feb 18, 2014, at 9:00 PM, "Weisenmiller, Robert@Energy" <Robert.Weisenmiller@energy.ca.gov> wrote:
>
> Ditto.
>
> Sent from my iPhone
>
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>>> Office of the Chair
>>> California Air Resources Board
>>> (916) 323-2602 (office)
>>> (916) 217-4714 (cell)
>>>
>>> <winmail.dat>
>

Tab 18

Message

From: Kelley, Kristen [kkelley@caiso.com]
Sent: 2/19/2014 7:31:02 AM
To: 'Picker, Michael' [Michael.Picker@cpuc.ca.gov]
Subject: RE: March 4th EP meeting: SONGS update?

Thanks. I got the same date update yesterday. I'll let the team know.

From: Picker, Michael [mailto:Michael.Picker@cpuc.ca.gov]
Sent: Tuesday, February 18, 2014 9:05 PM
To: Kelley, Kristen
Subject: Fwd: March 4th EP meeting: SONGS update?

< EXTERNAL email. Evaluate before clicking. >

I think that March 4 is our likely new date. Note the discussion about priorities.

Michael Picker

Redacted

Begin forwarded message:

> **From:** "Weisenmiller, Robert@Energy" <Robert.Weisenmiller@energy.ca.gov>
> **Date:** February 18, 2014 9:00:36 PM PST
> **To:** "Rossi, Michael@HSR" <rossim@aol.com>
> **Cc:** "McCarthy, Ryan@ARB" <rmccarth@arb.ca.gov>, "Michael.picker@cpuc.ca.gov." <Michael.picker@cpuc.ca.gov>, "Rechtschaffen, Cliff" <cliff.rechtschaffen@gov.ca.gov>, "Nichols, Mary D. @ARB" <mnichols@arb.ca.gov>
> **Subject: Re: March 4th EP meeting: SONGS update?**
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Sent from my iPhone

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Sent from my iPhone

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Thanks,

Ryan

Ryan McCarthy, PhD

Science and Technology Policy Advisor

Office of the Chair

California Air Resources Board

(916) 323-2602 (office)

Redacted (cell)

<winmail.dat>

Tab 22

Message

From: Nichols, Mary D. @ARB [mnichols@arb.ca.gov]
Sent: 2/21/2014 6:21:54 PM
To: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
CC: Picker, Michael [Michael.Picker@cpuc.ca.gov]; Rechtschaffen, Cliff [cliff.rechtschaffen@gov.ca.gov]; Mike Rossi [Mike.Rossi@GOV.CA.GOV]; McCarthy, Ryan@ARB [rmccarth@arb.ca.gov]; Barker, Kevin@Energy [Kevin.Barker@energy.ca.gov]
Subject: Re: Energy Principals meeting with renewable companies

Nancy is a finance person not a developer. If we are going in that direction there are others we should include. Which would make the meeting too big.

Sent from my iPhone

On Feb 21, 2014, at 5:15 PM, "Weisenmiller, Robert@Energy" <Robert.Weisenmiller@energy.ca.gov> wrote:

> I think we all agree that the renewable group needs to be limited in size. (Mary, Ryan ---Is our agenda, Renewables and SONGS only, or is there a drought component? Any other components??)
>
> There seems to be no problems with the notion that we need to add geothermal. I assume any invits go from Mary. Kevin can provide contact info to Ryan (Jack Fusco of Calpine and Jonathan Weisgall of MidAmerican although each are likely to send the appropriate staff). I also assume each company sends only one representative.
>
> We are getting lots of flavors of solar. I would suggest Recurrent for Trina Solar . I believe the letter was signed by NRG, Sunpower, EDF Renewables and Terragen.
>
> Sounds like Abengoa is a deal. Next Era is both wind and solar, so agree with Picker they make sense.
>
> That leaves the tenth as Nancy Pfund, Iberdrola, Solar City or First Solar. Solar City??
>
> Bob

From: Picker, Michael [mailto:Michael.Picker@cpuc.ca.gov]
Sent: Friday, February 21, 2014 1:10 PM
To: Rechtschaffen, Cliff; Weisenmiller, Robert@Energy; Nichols, Mary D. @ARB
Cc: Mike Rossi; McCarthy, Ryan@ARB
Subject: RE: Energy Principals meeting with renewable companies

Arno Harris from Recurrent. His perspective is different on many issues from other solar developers.

A couple of large scale solar (e.g), Abengoa and NextEra who represent diverse technologies, as well as panel manufacturers who develop as a means of getting their technology to market (for example First Solar and Sunpower) and then sell their projects.

Wind: Terragen, Iberdrola, EDF Renewables and Next Era.

But we can't spend all afternoon with them. This is handholding, and the review of reliability efforts in SoCal is core to our mission.

From: Cliff Rechtschaffen [mailto:Cliff.Rechtschaffen@GOV.CA.GOV]
Sent: Friday, February 21, 2014 12:55 PM
To: 'Weisenmiller, Robert@Energy'; Nichols, Mary D. @ARB
Cc: Picker, Michael; Mike Rossi; McCarthy, Ryan@ARB
Subject: RE: Energy Principals meeting with renewable companies

I would say let's add Calpine & Mid-American. I think the Wyoming wind (and biomass) issues are sufficiently different (and complex) that we can keep separate. And I'm worried about keeping the group manageable for 45 mintues.

From: Weisenmiller, Robert@Energy [mailto:Robert.Weisenmiller@energy.ca.gov]
Sent: Friday, February 21, 2014 12:37 PM
To: Nichols, Mary D. @ARB; Cliff Rechtschaffen
Cc: Michael.picker@cpuc.ca.gov. (Michael.picker@cpuc.ca.gov); Mike Rossi; McCarthy, Ryan@ARB
Subject: RE: Energy Principals meeting with renewable companies

Current signers are solar and wind. David's additions add the rest of the solar mosaic. While we need to keep the group small, we need to add Calpine (Geysers) and Mid-american (Imperial) to cover the geothermal base. (Both companies have substantial amount of existing geothermal that will be uncontracted by the end of the year.) Wyoming wind, which the Governor has raised a couple of times with me. Abengoa Solar, which is the Spanish Bechtel and has a large solar presence in California and around the world. If we need a biomass presence, it would be Covanta and/or Sierra Pacific.

Bob

From: Nichols, Mary D. @ARB [mailto:mnichols@arb.ca.gov]
Sent: Friday, February 21, 2014 12:13 PM
To: Rechtschaffen, Cliff
Cc: Michael.picker@cpuc.ca.gov. (Michael.picker@cpuc.ca.gov); Weisenmiller, Robert@Energy; Mike Rossi; McCarthy, Ryan@ARB
Subject: Re: Energy Principals meeting with renewable companies

Sounds good to me.

Sent from my iPhone

On Feb 21, 2014, at 12:06 PM, "Cliff Rechtschaffen" <Cliff.Rechtschaffen@GOV.CA.GOV> wrote:

> I talked to David Hochschild about the upcoming EP meeting with renewable execs. He suggested adding two people: (1) Mark Mendenhall of Trina Solar, one of largest PV manufacturers in the world. Mark was at a meeting with solar

execs and the governor last year & was very constructive. (2) Nancy Pfund, of DBL Investors. DBL has invested in utility scale projects like Bright Solar as well as rooftop solar companies like Solar City (& Telsa & others). The advantage of Nancy is that she would straddle both the DG & large scale solar & we would not have to worry about enlarging to include the rooftop companies. I think these would be more than enough

Tab 25

To: Nichols, Mary D. @ARB[mnichols@arb.ca.gov]
Cc: Rechtschaffen, Cliff[cliff.rechtschaffen@gov.ca.gov]; McCarthy, Ryan@ARB[rmccarth@arb.ca.gov]; Picker, Michael[Michael.Picker@cpuc.ca.gov]; Mike Rossi[Mike.Rossi@GOV.CA.GOV]; Barker, Kevin@Energy[Kevin.Barker@energy.ca.gov]
From: Weisenmiller, Robert@Energy
Sent: Sat 2/22/2014 2:02:26 PM
Subject: Re: Energy Principals meeting with renewable companies

I don't know how the original firms were selected but it is not very representative of the renewable industry in California. There are very different perspectives among the renewable firms in California and these issues will involve trade offs.

At the same time I don't know how we can not have geothermal in the room given by the end of the year we are likely to have hundreds of mws if existing capacity uncontracted at the geysers and imperial valley. Plus Mid American has invested about $8 billion in California renewables.

Agree it is a real dilemma which was why I was trying for at least a representative mix.

Bob

Sent from my iPhone

On Feb 22, 2014, at 2:14 PM, "Nichols, Mary D. @ARB" <mnichols@arb.ca.gov> wrote:

> I think what started us down the expansion track was a concern that having just the original 5 meet with the Principals was according them a privileged position vis a vis all other renewable companies. We have a real dilemma here.

Sent from my iPhone

On Feb 22, 2014, at 9:57 AM, "Cliff Rechtschaffen" <Cliff.Rechtschaffen@GOV.CA.GOV> wrote:

> Can I make a friendly amendment, even if it goes against my earlier proposed additions, and suggest that we scale this back, perhaps just to original group of 5 who met with governor? I'm worried that if we add a half dozen additional execs we will create expectations that this meeting is a big deal & make logistics more complicated, as different companies may have different perspectives & want to make different presentations. Especially since we are trying to limit the meeting to 45 minutes so that we can concentrate on the SONGs update. Obviously this is just one part of longer process that will involve many more meetings with renewable industry.

From: McCarthy, Ryan@ARB [mailto:rmccarth@arb.ca.gov]
Sent: Friday, February 21, 2014 5:32 PM
To: Weisenmiller, Robert@Energy; Picker, Michael; Cliff Rechtschaffen; Nichols, Mary D. @ARB
Cc: Mike Rossi; Barker, Kevin@Energy
Subject: RE: Energy Principals meeting with renewable companies

Good summary, thanks. Was just trying to write something up, myself.

We'll send invites from Mary. I assume agenda is just renewables folks and SONGS, and that that will already more than fill the time, but if a drought item is needed, let me know. How much time do you think SONGS will take, and is there a specific framing or background items related to SONGS you'd like on the agenda? I can follow up with you separately to prepare for that item.

Here's what I have so for renewable invites, I think pretty much what Bob said. Who to ax, or is anyone missing? Do you all agree with Bob on Solar City for the 10th spot, out of the last group? I'll reach out to Kevin for contact info, but please let me know if you have suggested contacts for the other companies on this list.

1. Arno Harris, Recurrent
2. Jack Fusco, Calpine
3. Jonathan Weisgall, Mid-American
4. NRG
5. Sunpower
6. EDF Renewables
7. Terragen
8. Abengoa
9. NextEra

10. Nancy Pfund, DBL Investors
11. First Solar
12. Iberdrola
13. Solar City
14. Mark Mendenhall, Trina Solar

Ryan

From: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
Sent: Friday, February 21, 2014 5:15 PM
To: Picker, Michael; Rechtschaffen, Cliff; Nichols, Mary D. @ARB
Cc: Mike Rossi; McCarthy, Ryan@ARB; Barker, Kevin@Energy
Subject: RE: Energy Principals meeting with renewable companies

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Sounds like Abengoa is a deal. Next Era is both wind and solar, so agree with Picker they make sense.

That leaves the tenth as Nancy Pfund, Iberdrola, Solar City or First Solar. Solar City??

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To: Rechtschaffen, Cliff; Weisenmiller, Robert@Energy; Nichols, Mary D. @ARB
Cc: Mike Rossi; McCarthy, Ryan@ARB
Subject: RE: Energy Principals meeting with renewable companies

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Wind: Terragen, Iberdrola, EDF Renewables and Next Era.

But we can't spend all afternoon with them. This is handholding, and the review of reliability efforts in SoCal is core to our mission.

From: Cliff Rechtschaffen [mailto:Cliff.Rechtschaffen@GOV.CA.GOV]
Sent: Friday, February 21, 2014 12:55 PM
To: 'Weisenmiller, Robert@Energy'; Nichols, Mary D. @ARB
Cc: Picker, Michael; Mike Rossi; McCarthy, Ryan@ARB
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Tab 28

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Sent: Sunday, February 23, 2014 8:58 AM
To: Nichols, Mary D. @ARB
Cc: Picker, Michael; Mike Rossi; Rechtschaffen, Cliff; McCarthy, Ryan@ARB; Barker, Kevin@Energy
Subject: Re: Energy Principals meeting with renewable companies

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Sent from my iPhone

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Sent: Sun 2/23/2014 9:55:19 AM
Subject: Re: Energy Principals meeting with renewable companies

You got it.

Sent from my iPhone

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Tab 33

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Cc: Rechtschaffen, Cliff; Mike Rossi; Nichols, Mary D. @ARB; Picker, Michael; Barker, Kevin@Energy
Subject: Re: Energy Principals meeting with renewable companies

Assume the invites go to those who signed the letter. Sure Cliff has the letter and probably the addresses. Kevin can help with addresses

Bob

Sent from my iPhone

On Feb 25, 2014, at 5:47 PM, "McCarthy, Ryan@ARB" <rmccarth@arb.ca.gov> wrote:

> Can someone please send me the names and contact info for these folks and we'll get invitations out to them from Mary?
>
> Thanks,
> Ryan
>
> ---
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> **Sent:** Sunday, February 23, 2014 3:44 PM
> **To:** Mike Rossi; Nichols, Mary D. @ARB; 'Picker, Michael'
> **Cc:** Weisenmiller, Robert@Energy; McCarthy, Ryan@ARB; Barker, Kevin@Energy
> **Subject:** RE: Energy Principals meeting with renewable companies
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> **Sent:** Sunday, February 23, 2014 10:47 AM
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8. Abengoa
9. NextEra

10. Nancy Pfund, DBL Investors
11. First Solar
12. Iberdrola
13. Solar City
14. Mark Mendenhall, Trina Solar

Ryan

From: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]

Sent: Friday, February 21, 2014 5:15 PM
To: Picker, Michael; Rechtschaffen, Cliff; Nichols, Mary D. @ARB
Cc: Mike Rossi; McCarthy, Ryan@ARB; Barker, Kevin@Energy
Subject: RE: Energy Principals meeting with renewable companies

I think we all agree that the renewable group needs to be limited in size. (Mary, Ryan ---Is our agenda, Renewables and SONGS only, or is there a drought component? Any other components??)

There seems to be no problems with the notion that we need to add geothermal. I assume any invits go from Mary. Kevin can provide contact info to Ryan (Jack Fusco of Calpine and Jonathan Weisgall of MidAmerican although each are likely to send the appropriate staff). I also assume each company sends only one representative.

We are getting lots of flavors of solar. I would suggest Recurrent for Trina Solar . I believe the letter was signed by NRG, Sunpower, EDF Renewables and Terragen.

Sounds like Abengoa is a deal. Next Era is both wind and solar, so agree with Picker they make sense.

That leaves the tenth as Nancy Pfund, Iberdrola, Solar City or First Solar. Solar City??

Bob

From: Picker, Michael [mailto:Michael.Picker@cpuc.ca.gov]
Sent: Friday, February 21, 2014 1:10 PM
To: Rechtschaffen, Cliff; Weisenmiller, Robert@Energy; Nichols, Mary D. @ARB
Cc: Mike Rossi; McCarthy, Ryan@ARB
Subject: RE: Energy Principals meeting with renewable companies

Arno Harris from Recurrent. His perspective is different on many issues from other solar developers.

A couple of large scale solar (e.g), Abengoa and NextEra who represent diverse technologies, as well as panel manufacturers who develop as a means of getting their technology to market (for example First Solar and Sunpower) and then sell their projects.

Wind: Terragen, Iberdrola, EDF Renewables and Next Era.

But we can't spend all afternoon with them. This is handholding, and the review of reliability efforts in SoCal is core to our mission.

From: Cliff Rechtschaffen [mailto:Cliff.Rechtschaffen@GOV.CA.GOV]
Sent: Friday, February 21, 2014 12:55 PM

To: 'Weisenmiller, Robert@Energy'; Nichols, Mary D. @ARB
Cc: Picker, Michael; Mike Rossi; McCarthy, Ryan@ARB
Subject: RE: Energy Principals meeting with renewable companies

I would say let's add Calpine & Mid-American. I think the Wyoming wind (and biomass) issues are sufficiently different (and complex) that we can keep separate. And I'm worried about keeping the group manageable for 45 mintues.

From: Weisenmiller, Robert@Energy [mailto:Robert.Weisenmiller@energy.ca.gov]
Sent: Friday, February 21, 2014 12:37 PM
To: Nichols, Mary D. @ARB; Cliff Rechtschaffen
Cc: Michael.picker@cpuc.ca.gov. (Michael.picker@cpuc.ca.gov); Mike Rossi; McCarthy, Ryan@ARB
Subject: RE: Energy Principals meeting with renewable companies

Current signers are solar and wind. David's additions add the rest of the solar mosaic. While we need to keep the group small, we need to add Calpine (Geysers) and Mid-american (Imperial) to cover the geothermal base. (Both companies have substantial amount of existing geothermal that will be uncontracted by the end of the year.) Wyoming wind, which the Governor has raised a couple of times with me. Abengoa Solar, which is the Spanish Bechtel and has a large solar presence in California and around the world. If we need a biomass presence, it would be Covanta and/or Sierra Pacific.

Bob

From: Nichols, Mary D. @ARB [mailto:mnichols@arb.ca.gov]
Sent: Friday, February 21, 2014 12:13 PM
To: Rechtschaffen, Cliff
Cc: Michael.picker@cpuc.ca.gov. (Michael.picker@cpuc.ca.gov); Weisenmiller, Robert@Energy; Mike Rossi; McCarthy, Ryan@ARB
Subject: Re: Energy Principals meeting with renewable companies

Sounds good to me.
Sent from my iPhone

On Feb 21, 2014, at 12:06 PM, "Cliff Rechtschaffen" <Cliff.Rechtschaffen@GOV.CA.GOV> wrote:

> I talked to David Hochschild about the upcoming EP meeting with renewable execs. He suggested adding two people: (1) Mark Mendenhall of Trina Solar, one of largest PV manufacturers in the world. Mark was at a meeting with solar execs and the governor last year & was very constructive. (2) Nancy Pfund, of DBL Investors. DBL has invested in utility scale

projects like Bright Solar as well as rooftop solar companies like Solar City (& Telsa & others). The advantage of Nancy is that she would straddle both the DG & large scale solar & we would not have to worry about enlarging to include the rooftop companies. I think these would be more than enough

Tab 36

From: Chaset, Nicolas L. <nicolas.chaset@cpuc.ca.gov>
Sent: Monday, March 03, 2014 12:50 PM
To: Picker, Michael; Hammond, Christine J.; ken.koss@cpuc.ca.gov; TerKeurst, Charlotte
Subject: To Do List - 3/3 - 3/7

Proceedings
-Continue oversight/review of LTPP Phase 4 Decision
-Monitor NEM transition PD
-Monitor progress of San Onofre Phase 1 Decision
-Work on Smart Inverter issue (ALJ staffing and policy direction)
-Meet with Commissioner and Staff regarding 2014 LTPP Scoping Memo

Misc Projects
-Initiate planning for Smart Grid conference
-Continue planning for Germany

Nicolas Chaset
Special Advisor for Distributed Energy Resources
Office of Governor Edmund G Brown, Jr
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

Tab 37

Message

From: Randolph, Edward F. [edward.randolph@cpuc.ca.gov]
Sent: 3/3/2014 7:27:20 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]; Peevey, Michael R. [michael.peevey@cpuc.ca.gov]
Subject: discussion of post SONGS planning at EP meeting

At the EP meeting tomorrow there will be a discussion of the planning process for meeting Southern California need post SONGS and the work tracking documents the staffs of the respective agencies have put together. The ISO is managing the work tracking, but most of the actual work is at the CPUC.

I think almost everything is on track. With the approval of Pio Pico, start of the new DR proceeding, approval track 1 of the LTPP, and likely approval of track 4 we are hitting the early milestones. Most of the concern that existed this summer has dissipated.

I am not going to be at the meeting since I need to be in SF for a meeting with the CAISO on other issues. Cynthia Walker will be there instead of me since she is the point person for ED on developing the planning documents. I wanted to flag two items of concern:

1) The first one is minor, but seems to have more discussion and is going to be set up for you to discuss on Tuesday. The issue is how we talk publicly about the resource needs now that there are draft proposals in LTPP and TPP that are likely to be approved.

   The SONGS planning staff proposal that was developed in August identified a need of 6,250 new MWs of need, of which 3,000 would be from conventional and 3,250 from preferred resources. Based on LTPP and the most recent IEPR forecasts the 6,250 number if more or less accurate still, but in LTPP track 4 we have moved away from the specific call out for conventional resources and instead are having SCE and SDG&E do all source procurement for up to 1,400 MW of resources. Even though there will very likely be conventional resource procured under the track 4 authorization, the commitment to try to do this through an all source procurement where conventional could be beaten out by other resources has one praise from almost all sides of the issue. **I fear that using the numbers from the staff white paper to discuss 3,000 MW of conventional resources will confuse the issues and is actually inconsistent with the events that have transpired since that paper was drafted. My preference would be to simply discuss the need as 6,250 MW of resources and not separate them out in any high level documents. Some specific projects will need to be called out in the details of the planning documents.**

   None of this actually changes outcome with proceedings at the CPUC, the CEC or the CAISO, but it could help reduce the headaches all the way around.

2) We still don't have dates set for triggering contingencies. My issue is not by what date do we need to have decisions made or permits issued, but by what dates does the ISO need to know that preferred resources are real and they can count on them. The issue here is that for some programs, they may need to up and running for a period of time for us to know they deliver real resources or real reductions.

Edward Randolph | Director, Energy Division
California Public Utilities Commission

505 Van Ness Avenue, Room 4004
San Francisco, CA, 94102
415-703-2083 | edward.randolph@cpuc.ca.gov

Tab 38

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From: Prosper, Terrie D. <terrie.prosper@cpuc.ca.gov>
Sent: Thursday, March 06, 2014 10:54 AM
To: Picker, Michael
Cc: TerKeurst, Charlotte
Subject: Roundtables in L.A.

Commissioner Picker,

Our May 1st Voting Meeting is in Los Angeles. When we have such meetings off-site, we typically do "roundtable" meetings with local elected officials, community leaders, and other stakeholders the day before. Basically there are three umbrella topics that stakeholders come in to talk to Commissioners about: 1) Energy, 2) Safety and Enforcement – All Industries, and 3) California's Drought and Water Conservation Measures. Below is a list of potential topics that may come up at the three roundtables.

I will tell you more about how this works in our meeting next week, but basically two Commissioners at a time sit with each of the three groups of stakeholders and have a free ranging conversation. The roundtables are not open to the public.

In a separate email I will send information on location and the hotel, and a calendar appointment will also be sent to you.

Terrie

Potential Topics

L.A.* Roundtables Prior to Voting Meeting

April 30, 2014

*Greater Los Angeles Area (or Southland) includes the Counties of Los Angeles, Orange, San Bernardino, Riverside, and Ventura.

- **Energy**
    - Impact of SONGS shutdown
        - Energy Replacements
            - Natural Gas-fired power plants
            - Preferred Resources, i.e., renewables, conservation, etc.
        - Costs: Who will pay now and going forward?
    - Renewable procurement
    - Energy efficiency programs
    - Solar panel installation (red tape) delays (DWP)
    - Energy storage
    - Use of EVs
        - Access
        - Charging Stations

- Greater participation by local government in CPUC regulatory process, as they play important role in implementation of energy projects
- Local government access to IOU energy data, as this data is critically important for the effective design and implementation of regional energy and climate action plans
- Community-scale integrated demand side management programs and projects.

- **Safety and Enforcement – All industries**
    - Passenger Carriers
        - TNCs
        - Limos
        - Charter Buses
    - MTA
    - Communications with IOUs when emergencies happen
    - Telecommunications – making broadband accessible to all and ensuring access to LifeLine
    - Energy infrastructure
        - Natural gas pipeline safety
            - Protecting infrastructure
    - Subway & Light rail extension to the Westside of L.A. continuing

- **California's Drought and Water Conservation Measures**
    - Governor's Drought Declaration
        - Conservation Measures
        - Water restrictions
        - Ground water replenishment

- Water Reservoirs
- Water Quality
    - Post Fukushima
    - Oil Spills
- Increasing water rates
- Aging infrastructure

****

Terrie Prosper
Director, News and Public Information Office
California Public Utilities Commission
(415) 703-2160
tdp@cpuc.ca.gov
Facebook | Twitter | www.cpuc.ca.gov

Tab 39

Message

From: Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Sent: 4/7/2014 1:05:06 PM
To: Koss, Kenneth L. [kenneth.koss@cpuc.ca.gov]; Picker, Michael [Michael.Picker@cpuc.ca.gov]; TerKeurst, Charlotte [charlotte.terkeurst@cpuc.ca.gov]; Hammond, Christine J. [christine.hammond@cpuc.ca.gov]; Emelo, Josephine [josephine.emelo@cpuc.ca.gov]; Banks, Juliane [juliane.banks@cpuc.ca.gov]
Subject: Week Ahead - Apr 7-11, 2014

-Complete Smart Inverter Scoping Memo
-Meet with ED and ALJ on LTPP Scoping Memo
-Commence drafting of Germany trip report
-review San Onofre settlement

Nicolas Chaset
Advisor
Office of Commissioner Michael Picker
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

-----Original Message-----
From: Koss, Kenneth L.
Sent: Monday, April 07, 2014 8:47 AM
To: Picker, Michael; TerKeurst, Charlotte; Hammond, Christine J.; Emelo, Josephine; Banks, Juliane; Chaset, Nicolas L.
Subject: K Koss - Week Ahead - Apr 7-11, 2014

For week of Apr 7-11: Ken Koss

In office all week
Comm. Meeting - Thursday

Activities:
- Contact UP re on-sight inspection in Roseville.
- Meet with B. Turner re Safety Plan - next steps - divisional one-pagers
- Review San Bruno OII filings

- Wed
  Meet with ALJ Hymes (w/ Michael, Charlotte) re Suburban Water GRC - PHC set for 4/14
  ALJ briefing (our staff) on Rules of Practice/Procedure

- Thurs
  Comm. Meeting
  PG&E briefing (w/ Michael, Charlotte) - substation security (viz. Metcalf)
  Note: Let's discuss at our Tues staff meeting

Tab 40

Message

From: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Sent: 4/14/2014 9:06:30 AM
To: Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Subject: FW: SONGS Mesa site
Attachments: SDG&E SONGS LTR.PDF

No rush on the Navy interconnection stuff. Let this settle out first.

Michael Picker
California Public Utilities Commission
(415) 703-2444

From: Weisenmiller, Robert@Energy [mailto:Robert.Weisenmiller@energy.ca.gov]
Sent: Monday, April 14, 2014 8:59 AM
To: Picker, Michael; Steve Berberich (SBerberich@caiso.com)
Cc: Karen Edson; Phil Pettingill (PPettingill@caiso.com)
Subject: FW: SONGS Mesa site

When I talked with McGinn on Friday he understood that we needed disturbed land …

From: Avery, James [mailto:JAvery@semprautilities.com]
Sent: Monday, April 14, 2014 8:55 AM
To: Weisenmiller, Robert@Energy; michael.peevey@cpuc.ca.gov; michael.peevey@cpuc.ca.gov
Cc: Thomas, Frank; Guebert, Dave
Subject: FW: SONGS Mesa site

Just received this from Camp Pendleton. The Mesa is off limits and they direct us to move the Synchronous Condenser to West of Interstate 5. We will review our options and report back later this week.
Jim

From: john.bullard@nmci.usmc.mil [mailto:john.bullard@nmci.usmc.mil]
Sent: Monday, April 14, 2014 7:36 AM
To: Avery, James
Cc: charles.r.reuning@usmc.mil
Subject: SONGS Mesa site

Mr. Avery,

I first want to thank you and your team for working diligently with us to consider alternate locations for the new substation and voltage stabilization equipment associated with the closure of the San Onofre Nuclear Generating Station (SONGS). We fully recognize the challenges that the Southern California electrical grid faces with this closure, and we are committed to finding a mutually acceptable solution. We also realize that your available options for the placement of this equipment are limited due to the required need date, potential environmental approvals required, existing transmission line infrastructure, and desire to minimize costs.

Our training space, mobility corridors, and airspace are critical to our ability to support the training of Marine units. Our existing training space is limited by our impact areas and is also degraded by environmental encumbrances. The SONGS Mesa site is a key maneuver corridor that links our landing beaches with coastal and inland training areas and ranges. Additionally, a portion of the existing SONGS Mesa site infrastructure could be used to support training requirements and the storage of military equipment. Thus, return of the SONGS Mesa site as a training area will minimize future encumbrances on the site and adjacent land, while providing both a critically needed maneuver corridor and mission-supporting infrastructure that will save significant military construction costs in the future. Accordingly, if the 5-acre synchronous condenser is to be located on Camp Pendleton, then it must be placed on the SONGS power plant easement, west of I-5. I ask that you begin discussions with Southern California Edison to this end. Our real estate team is available to assist, as necessary, regarding the future use of this land.

If you have any questions, I would be more than willing to discuss. Please contact CAPT Charles Reuning, my Assistant Chief of Staff, G-F (Facilities) at 760-725-6451.

Very Respectfully,

BGen J.W. Bullard

CG MCI West

760-725-5114/2926

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Tab 41

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From: Chaset, Nicolas L. <nicolas.chaset@cpuc.ca.gov>
Sent: Monday, April 14, 2014 9:40 AM
To: Picker, Michael
Subject: RE: SONGS Mesa site

Got it.

Nicolas Chaset
Advisor
Office of Commissioner Michael Picker
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

From: Picker, Michael
Sent: Monday, April 14, 2014 9:07 AM
To: Chaset, Nicolas L.
Subject: FW: SONGS Mesa site

No rush on the Navy interconnection stuff. Let this settle out first.

Michael Picker
California Public Utilities Commission
(415) 703-2444

From: Weisenmiller, Robert@Energy [mailto:Robert.Weisenmiller@energy.ca.gov]
Sent: Monday, April 14, 2014 8:59 AM
To: Picker, Michael; Steve Berberich (SBerberich@caiso.com)
Cc: Karen Edson; Phil Pettingill (PPettingill@caiso.com)
Subject: FW: SONGS Mesa site

When I talked with McGinn on Friday he understood that we needed disturbed land …

From: Avery, James [mailto:JAvery@semprautilities.com]
Sent: Monday, April 14, 2014 8:55 AM
To: Weisenmiller, Robert@Energy; michael.peevey@cpuc.ca.gov; michael.peevey@cpuc.ca.gov
Cc: Thomas, Frank; Guebert, Dave
Subject: FW: SONGS Mesa site

Just received this from Camp Pendleton. The Mesa is off limits and they direct us to move the Synchronous Condenser to West of Interstate 5. We will review our options and report back later this week.
Jim

From: john.bullard@nmci.usmc.mil [mailto:john.bullard@nmci.usmc.mil]
Sent: Monday, April 14, 2014 7:36 AM
To: Avery, James
Cc: charles.r.reuning@usmc.mil
Subject: SONGS Mesa site

Mr. Avery,

I first want to thank you and your team for working diligently with us to consider alternate locations for the new substation and voltage stabilization equipment associated with the closure of the San Onofre Nuclear Generating Station (SONGS). We fully recognize the challenges that the Southern California electrical grid faces with this closure, and we are committed to finding a mutually acceptable solution. We also realize that your available options for the placement of this equipment are limited due to the required need date, potential environmental approvals required, existing transmission line infrastructure, and desire to minimize costs.

Our training space, mobility corridors, and airspace are critical to our ability to support the training of Marine units. Our existing training space is limited by our impact areas and is also degraded by environmental encumbrances. The SONGS Mesa site is a key maneuver corridor that links our landing beaches with coastal and inland training areas and ranges. Additionally, a portion of the existing SONGS Mesa site infrastructure could be used to support training requirements and the storage of military equipment. Thus, return of the SONGS Mesa site as a training area will minimize future encumbrances on the site and adjacent land, while providing both a critically needed maneuver corridor and mission-supporting infrastructure that will save significant military construction costs in the future. Accordingly, if the 5-acre synchronous condenser is to be located on Camp Pendleton, then it must be placed on the SONGS power plant easement, west of I-5. I ask that you begin discussions with Southern California Edison to this end. Our real estate team is available to assist, as necessary, regarding the future use of this land.

If you have any questions, I would be more than willing to discuss. Please contact CAPT Charles Reuning, my Assistant Chief of Staff, G-F (Facilities) at 760-725-6451.

Very Respectfully,

BGen J.W. Bullard

CG MCI West

760 725 5114/2926

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Tab 42

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From: Koss, Kenneth L. <kenneth.koss@cpuc.ca.gov>
Sent: Wednesday, May 07, 2014 6:04 PM
To: Picker, Michael
Subject: RE: Item 38 - 5/15 comm meeting - Citation OIR

Just picked up your voicemail now. Christine and I had a late advisor candidate interview – and I just finished talking to Carol Brown re assigning this to our office. She sees no problem with it, but will let us know if Peevey has any concerns.

Also – you may have seen the email - ALJ Div. is holding the SONGS proceeding for two meetings (June 26th).

Ken,

From: Picker, Michael
Sent: Wednesday, May 07, 2014 3:20 PM
To: Koss, Kenneth L.
Subject: RE: Item 38 - 5/15 comm meeting - Citation OIR

Skimmed it; go ahead and talk to Carol.

Michael Picker
California Public Utilities Commission
(415) 703-2444

From: Koss, Kenneth L.
Sent: Wednesday, May 07, 2014 3:01 PM
To: Picker, Michael
Subject: FW: Item 38 - 5/15 comm meeting - Citation OIR

Michael – this would be a good proceeding for our office with you as Assigned Commissioner.
If you agree - do you want me to discuss with Carol re assigning it here, or you may wish to talk directly with Peevey.
Ken,

From: Koss, Kenneth L.
Sent: Tuesday, May 06, 2014 3:11 PM
To: Picker, Michael; Chaset, Nicolas L.; Hammond, Christine J.
Subject: Item 38 - 5/15 comm meeting - Citation OIR

E-version of the Citation OIR attached – Item 38 on the 5/15 agenda (pasted below).
Ken,

38
[12967]
New Order Instituting Rulemaking
R___________
Order Instituting Rulemaking on the Commission's Natural Gas and Electric Safety Citation Programs

PROPOSED OUTCOME:

→ Opens a Rulemaking to further implementation of the Commission's Natural Gas and Electric Safety Citation Programs.
→ Sets forth a proposed electric safety citation program for comment and adoption by the Commission in compliance with Senate Bill 291 (Stats. 2013, Ch. 601.)
→ Makes a minor addition to the Commission's existing Natural Gas Safety Citation Programs.
→ Provides a forum for making improvements and refinements to the Commission's Natural Gas and Electric Safety Citation Programs.

SAFETY CONSIDERATIONS:

→ Furthering the implementation of the Commission's Natural Gas and Electric Safety Citation Programs will establish and refine additional regulatory tools to ensure compliance with natural gas and electric safety laws and rules.

ESTIMATED COST:

→ Unknown.
5/

Tab 44

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From: Koss, Kenneth L. <kenneth.koss@cpuc.ca.gov>
Sent: Monday, May 12, 2014 12:15 PM
To: Picker, Michael
Cc: Hammond, Christine J.; Chaset, Nicolas L.
Subject: FW: SONGs Settlement Hearing on Wednesday 5/14 at 1:30 pm

This has to do with the 10-day notice provision, so only Cmsrs Florio and Peevey will attend.
Nick – can you sit-in for our office.
Ken,

From: Khosrowjah, Sepideh
Sent: Monday, May 12, 2014 11:39 AM
To: Brown, Carol A.; Katague, Ditas; Fitch, Julie A.; Koss, Kenneth L.
Cc: Dudney, Kevin; Darling, Melanie
Subject: SONGs Settlement Hearing on Wednesday 5/14 at 1:30 pm

Dear Chiefs,
As some of you may know, we have a hearing on the SONGs settlement on 5/14/14. Unfortunately, this hearing was not noticed in a way that a quorum of Commissioners could participate. For clarification purposes, this is **NOT an All Party and Not an Oral argument**, it is a hearing as required by Rule 12. Commissioner Florio, as the assigned Commissioner and President Peevey, as his BK partner will be there. The ALJs can brief the other Commissioners on the hearing and your advisors can participate.
Thanks for your understanding,
Sepideh

Sepideh Khosrowjah
Commissioner Florio's Chief of Staff
Sepideh.khosrowjah@cpuc.ca.gov
505 Van Ness Ave., Room 5201, San Francisco, Ca 94102
(o) 415-703-1190
(c) 415-271-2760

Tab 45

From: Chaset, Nicolas L. <nicolas.chaset@cpuc.ca.gov>
Sent: Friday, May 16, 2014 10:55 AM
To: Picker, Michael
Subject: FW: Utility Working Group from ASN/CA Energy Meeting

I have been hanging back on these issues per your direction. Let me know if you would like me to re-engage

Nicolas Chaset
Advisor
Office of Commissioner Michael Picker
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

-----Original Message-----
From: Kawamura, Calvin Y CIV NAVFAC SW [mailto:calvin.kawamura@navy.mil]
Sent: Thursday, May 15, 2014 1:40 PM
To: Chaset, Nicolas L.
Cc: Faryan, Marykay CIV N05; Friedman, Randal A CIV CNRSW, N40; Lindsey, Bernard J CIV NAVFAC SW; Parry, Christopher F CIV NAVFACSW, swopmd; Huber, Michael CIV CNRSW, N40 Env
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Nick,
I wanted to give you a quick update on some of our current efforts. As you know we've been intimately involved with some of the legislative proceedings, as our commanding officer testified at a hearing several weeks ago. In addition to that, through our legislative liaison we have discussed and made recommendations on 2469 with staff in Mullins and Bradfords offices respectively.

On our front here San Diego we've had several meetings with SDGE at the ground level and they have been responsive to our feedback. In general, SDGE has never obstructed renewable development and has maintained a favorable interpretation of Rule 21 for us where real time monitoring of our existing generation assets are not required. In one of the conversations, they offered to file a Navy specific GO 96 filing if that was our desire. We'll continue to discuss.

We are scheduled to meet with SCE next week. I spoke to Dan Tunnecliff yesterday and he stated that one of their VP's is pressing to get answers on how they can better serve us and they seem to be open to discussions. The bulk of the problems we have had are with SCE's interconnection protocols. Without getting into the weeds, we have had small PV systems locked out by SCE in the past because interconnection procedures weren't followed. Currently at our Navy base in China Lake, we have around 300kw of PV offline until the monitoring issues are resolved. This may come at a very costly investment on our part for communication infrastructure because wireless communication isn't allowed on that base.

That's the summary for now. We have not heard much from the other services other than the Army having problems at Ft. Irwin with SCE's interconnection process. Our Marine Corps installations are experiencing similar pushback from SCE as with the Navy. I'm sure you're aware of the MCLB Barstow legislation.

Once we have this initial meeting with SCE, maybe we can all gather up with both of the utilities. Dan mentioned he was going to be in Sacramento the last week of May to meet CPUC, CEC and Governors office regarding this exact topic. Maybe you're in that meeting. Not sure if anyone from Navy or other services were invited.

We will keep you posted to follow up.

Thank you,

Calvin Kawamura, PE
NAVFAC SW Renewable Program Office
(619) 532-1813

-----Original Message-----
From: Chaset, Nicolas L. [mailto:nicolas.chaset@cpuc.ca.gov]
Sent: Thursday, April 03, 2014 4:51 PM
To: Kawamura, Calvin Y CIV NAVFAC SW
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Calvin
I look forward to hearing from you.
Nick

Nicolas Chaset
Advisor
Office of Commissioner Michael Picker
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

-----Original Message-----
From: Kawamura, Calvin Y CIV NAVFAC SW [mailto:calvin.kawamura@navy.mil]
Sent: Thursday, March 27, 2014 8:48 AM
To: Chaset, Nicolas L.; michael.picker@cpuc.com
Cc: Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Faryan, Marykay CIV N05; Randolph, Edward F.; Randal Friedman; Liotta, Rita M CIV WEST Counsel; Cummins, John M CIV NAVFAC SW
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Nick,
Thank you for your response. We will huddle with the team here, and confer with the Marine Corps and the other services.

We will get back to you shortly.

Regards,

Calvin Kawamura, PE
NAVFAC SW Renewable Program Office

(619) 532-1813

-----Original Message-----
From: Chaset, Nicolas L. [mailto:nicolas.chaset@cpuc.ca.gov]
Sent: Thursday, March 20, 2014 12:58 PM
To: Kawamura, Calvin Y CIV NAVFAC SW; michael.picker@cpuc.com
Cc: Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Faryan, Marykay CIV N05; Randolph, Edward F.; Randal Friedman; Liotta, Rita M CIV WEST Counsel; Cummins, John M CIV NAVFAC SW
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Calvin
Thank you for sending this around. As we work to make progress here, Id appreciate your help with the following.
-list of each project or facility that is currently facing an energy related issue (ex: Navy Base San Diego wants to install additional rooftop solar but is currently unable to do so because of NEM cap) -description of the specific issue (ex: Navy Base San Diego wants to install additional rooftop solar but is currently unable to do so because of NEM cap and if the site is unable to participate in NEM, SDGE will require charges be added to the sites bill that will make the deployment of rooftop solar on base uneconomic) -review of specific remedies that have already been discussed/considered to address the outstanding issue -review of past communication with the utility related to the outstanding issue

Once I have everything from you, I will plan a follow up meeting to discuss potential remedies.

Nicolas Chaset
Special Advisor for Distributed Energy Resources Office of Governor Edmund G Brown, Jr California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

-----Original Message-----
From: Kawamura, Calvin Y CIV NAVFAC SW [mailto:calvin.kawamura@navy.mil]
Sent: Thursday, March 13, 2014 10:58 AM
To: michael.picker@cpuc.com
Cc: Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Faryan, Marykay CIV N05; Randolph, Edward F.; Randal Friedman; Chaset, Nicolas L.; Liotta, Rita M CIV WEST Counsel; Cummins, John M CIV NAVFAC SW
Subject: Utility Working Group from ASN/CA Energy Meeting

Commissioner Picker,
On behalf of Capt. D. Banaji, Commanding Officer of NAVFAC SW, am reaching out to you as a follow up to our meeting last month. We would like to engage with you and your staff to make progress towards mutually beneficial improvements in developing more renewable distributed generation on our installations.

Please see attached draft charter for consideration as a framework for moving forward. We request your feedback on our main concerns as summarized in the charter statement and any recommended courses of action. We will be contacting the other services to get their input and appropriate personnel involved in the Working Group.

We have already had face to face discussions with SDGE regarding these topics and they have given us some positive feedback on what they can do to improve current challenges on our installations in their territory. One of our goals is to get similar engagement with SCE and PGE.

We look forward to hearing from you and working with you on this effort. We look to have a follow up meeting or call within the next few weeks to discuss our way forward.

Thank you. Very Respectfully,

Calvin Kawamura, PE
NAVFAC SW Renewable Program Office
(619) 532-1813

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Sent: Tuesday, March 04, 2014 6:17 PM
To: Kang, David I CDR OASN (EI&E), ODASN Energy; Griffin, Robert M Jr. SES NAVFAC HQ, ACQ; Forrest, Scott D SES NAVFAC HQ, AM; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Garin, Patrick A I&L; Marrs, Richard L CIV HQMC; Lindsey, Yancy CAPT OASN (EI&E), Executive Assistant to ASN (EI&E); Banaji, Darius CAPT NAVFAC SW; Kliem, John CAPT CNIC HQ, N44; Páez, Bryon J CIV OASN (EI&E), ODASN Energy; Santiago, Angel L LCDR OPNAV, N46; Coleman, Andre L CDR OASN (EI&E), OPDASN EI&E; Hilley, Ryan CIV OASN (EI&E), ODASN Energy; Heckmann, John V CAPT NAVFAC HQ, OPS; Wolfe, Steven R CIV MCI WEST FACILITIES, MCIWEST; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Autry, Keith CAPT OASN (EI&E), OPDASN EI&E; Donovan, Kathryn A CAPT NAVFAC HQ, PW; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Landers, Lynn M CIV HQMC, MCICOM G3/5/7; Clark, Gordon E CIV NAVFAC HQ, AM; Bordelon, Matthew CIV I&L, CL (LFL); Wainwright, Ben V LCDR OASN (EI&E), Military Aide to ASN EI&E; Morin, Kara L CIV MCIWEST-MCB CAMPEN CG STAFF, SSEC; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Ward, Thomas W Col MCIWEST/MCB CAMPEN G3 Operations & Training, AC/S MCIWEST/MCB CAMPEN G-3 Operations & Training; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Christman, Patrick L CIV MCI WEST WREC, WREC; Lyon, Eric M Maj MCBPAC, WACO; Norquist, Stanley W CIV MCIWEST-MCBCP, Environmental Security; Pearcy, Ralph E CIV MARFORPAC, WACO; Thelin, Richard W CIV MARFORPAC, WACO; Carretti, John M CIV AC/S O&T, TRMD; White, Phillip A CIV MCI WEST Facilities Division, MCI WEST G-4(I&L); Gilleskie, Robert J CIV MCI WEST G-4, MCI WEST G-4; McKinley CIV Ned; Wenderoth, Stephen Civ, Counsel for CMC; Lundstrom, Thomas J CIV OASN (EI&E), OAGC EI&E; Hector, Jermaine N CIV NAVFAC HQ, ACQ; dslayton@stanford.edu; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Shwisberg, Lauren CIV PEO SHIPS, PMS325; Morin, Kara L CIV MCIWEST-MCB CAMPEN CG STAFF, SSEC; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Ward, Thomas W Col MCIWEST/MCB CAMPEN G3 Operations & Training, AC/S MCIWEST/MCB CAMPEN G-3 Operations & Training; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Christman, Patrick L CIV MCI WEST WREC, WREC; Lyon, Eric M Maj MCBPAC, WACO; Norquist, Stanley W CIV MCIWEST-MCBCP, Environmental Security; Pearcy, Ralph E CIV MARFORPAC, WACO; Thelin, Richard W CIV MARFORPAC, WACO; Carretti, John M CIV AC/S O&T, TRMD; White, Phillip A CIV MCI WEST Facilities Division, MCI WEST G-4(I&L); Gilleskie, Robert J CIV MCI WEST G-4, MCI WEST G-4; McKinley CIV Ned; Lorge, Patrick RADM CNRSW, N00; Banaji, Darius CAPT NAVFAC SW; Bixler, David B CIV NAVFAC SW; Roberts, Yvonne CDR NAVFAC SW, FISD; Merrill, Reid K CIV NAVFAC SW, FISD; Haskett, Christopher CIV NAVFAC SW, ESWD; Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Kawamura, Calvin Y CIV NAVFAC SW; Faryan, Marykay CIV N05; Garin, Patrick A I&L; Orndorff, Ryan CIV I&L, LFL; Heinrichs, David A CIV HQMC, HQMC LFF; Forrest, Scott D SES NAVFAC HQ, AM; MF1@cpuc.ca.gov; Nichols, Mary D. @ARB; Oglesby, Rob@Energy; Weisenmiller, Robert@Energy; edward.randolph@cpuc.ca.gov; Scott, Janea@Energy; james.bartridge@energy.ca.gov; Gibbs, Michael@ARB; mpo@cpuc.ca.gov; sberberich@caiso.com; nmillar@caiso.com; ppettingill@caiso.com; michael.picker@cpuc.com; Gravely, Mike@Energy; wade.crowfoot@gov.ca.gov; dslayton@stanford.edu; Bevan, Analisa@ARB
Cc: Shwisberg, Lauren CIV PEO SHIPS, PMS325; Coleman, Andre L CDR OASN (EI&E), OPDASN EI&E; Stites, Alex D CAPT NAVFAC Washington, OPS; McGinn, Dennis V HON ASN (EI&E)
Subject: RE: SONGS Meeting - Draft minutes

Thank you, David and team for pulling these minutes together. The minutes accurately reflect the topics discussed at the meeting in a very concise fashion.

I wanted to quickly respond to the two pieces of information from the state side regarding the working groups.

1. SONGS working group - CAISO Co-chair identified was Phil Pettingill. His email contact is ppettingill@caiso.com.
2. Transportation pilot - Annalisa Bevan (CARB) Her email contact is abevan@arb.ca.gov

Further, I also wanted to reiterate that the co-chairs for the 6 working groups should reach out to the other agencies to establish the larger working group that will be tackling the issues. The co-chairs should not feel the need to work through identified issues only amongst themselves, in fact other agencies and staff may be critical on a specific topic.

I would also like to instill some sense of urgency to establish the working groups soon. The one month update from the meeting in San Diego is coming up in a few weeks.

I will follow up with David with a monthly update template and we can circulate that with the group.

Best Regards,

Kevin

Kevin M. Barker, Chief of Staff to
Chair Robert B. Weisenmiller
California Energy Commission
(916) 651-6176
1516 Ninth Street MS-33
Sacramento, CA 95814
kevin.barker@energy.ca.gov

-----Original Message-----
From: Kang, David I CDR OASN (EI&E), ODASN Energy [mailto:david.kang@navy.mil]
Sent: Tuesday, March 04, 2014 1:17 PM
To: Barker, Kevin@Energy; Griffin, Robert M Jr. SES NAVFAC HQ, ACQ; Forrest, Scott D SES NAVFAC HQ, AM; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Garin, Patrick A I&L; Marrs, Richard L CIV HQMC; Lindsey, Yancy CAPT OASN (EI&E), Executive Assistant to ASN (EI&E); Banaji, Darius CAPT NAVFAC SW; Kliem, John CAPT CNIC HQ, N44; Páez, Bryon J CIV OASN (EI&E), ODASN Energy; Santiago, Angel L LCDR OPNAV, N46; Coleman, Andre L CDR OASN (EI&E), OPDASN EI&E; Hilley, Ryan CIV OASN (EI&E), ODASN Energy; Heckmann, John V CAPT NAVFAC HQ, OPS; Wolfe, Steven R CIV MCI WEST FACILITIES, MCIWEST; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Autry, Keith CAPT OASN (EI&E), OPDASN EI&E; Donovan, Kathryn A CAPT NAVFAC HQ, PW; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Landers, Lynn M CIV HQMC, MCICOM G3/5/7; Clark, Gordon E CIV NAVFAC HQ, AM; Bordelon, Matthew CIV I&L, CL (LFL); Wainwright, Ben V LCDR OASN (EI&E), Military Aide to ASN EI&E; Morin, Kara L CIV MCIWEST-MCB CAMPEN CG STAFF, SSEC; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Ward, Thomas W Col MCIWEST/MCB CAMPEN G3 Operations & Training, AC/S MCIWEST/MCB CAMPEN G-3 Operations & Training; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Christman, Patrick L CIV MCI WEST WREC, WREC; Lyon, Eric M Maj MCBPAC, WACO; Norquist, Stanley W CIV MCIWEST-MCBCP, Environmental Security; Pearcy, Ralph E CIV MARFORPAC, WACO; Thelin, Richard W CIV MARFORPAC, WACO; Carretti, John M CIV AC/S O&T, TRMD; White, Phillip A CIV MCI WEST Facilities Division, MCI WEST G-4(I&L); Gilleskie, Robert J CIV MCI WEST G-4, MCI WEST G-4; McKinley CIV Ned; Wenderoth, Stephen Civ, Counsel for CMC; Lundstrom, Thomas J CIV OASN (EI&E), OAGC EI&E; Hector, Jermaine N CIV NAVFAC HQ, ACQ; dslayton@stanford.edu; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Shwisberg, Lauren CIV PEO SHIPS, PMS325; Morin, Kara L CIV MCIWEST-MCB

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Subject: SONGS Meeting - Draft minutes

Kevin/DON Team, please review the minutes of the SONGS meeting and provide any comments or changes. Please use track changes for any revisions and send to me COB, Tuesday, 11 Mar.

We have listed the six working groups identified during our meeting. Please verify co-chairs for those working groups from NAVFAC SW, MCIWEST, and State agencies. I am missing the following info for co-chairs:

1. SONGS working group - CAISO Co-chair name/contact info.
2. Transportation pilot - Need contact info for Annalisa Bevan (CARB) 3. Transportation pilot - Need MCIWEST POC

ASN McGinn and Dr. Weisenmiller will be holding monthly progress updates via phonecon. Additional information will be provided to the working group chairs to outline expectations for monthly updates/progress with their working groups and the issues/opportunities that have been identified.

Please let me know if you have any questions.

Very Respectfully,

David Kang, P.E.
CDR, CEC, USN
Director for Shore Energy
Office of the Deputy Assistant Secretary of the Navy for Energy
1000 Navy Pentagon, RM 5E157
Washington DC 20350-1000
Phone: (571) 256-9152
Cell: (703) 980-7662
SIPR: david.kang@navy.smil.mil

Tab 46

From: Picker, Michael <Michael.Picker@cpuc.ca.gov>
Sent: Friday, May 16, 2014 11:11 AM
To: Chaset, Nicolas L.
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Hold off to see if the meeting happens.

Michael Picker
California Public Utilities Commission
(415) 703-2444

-----Original Message-----
From: Chaset, Nicolas L.
Sent: Friday, May 16, 2014 10:55 AM
To: Picker, Michael
Subject: FW: Utility Working Group from ASN/CA Energy Meeting

I have been hanging back on these issues per your direction. Let me know if you would like me to re-engage

Nicolas Chaset
Advisor
Office of Commissioner Michael Picker
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

-----Original Message-----
From: Kawamura, Calvin Y CIV NAVFAC SW [mailto:calvin.kawamura@navy.mil]
Sent: Thursday, May 15, 2014 1:40 PM
To: Chaset, Nicolas L.
Cc: Faryan, Marykay CIV N05; Friedman, Randal A CIV CNRSW, N40; Lindsey, Bernard J CIV NAVFAC SW; Parry, Christopher F CIV NAVFACSW, swopmd; Huber, Michael CIV CNRSW, N40 Env
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Nick,
I wanted to give you a quick update on some of our current efforts. As you know we've been intimately involved with some of the legislative proceedings, as our commanding officer testified at a hearing several weeks ago. In addition to that, through our legislative liaison we have discussed and made recommendations on 2469 with staff in Mullins and Bradfords offices respectively.

On our front here San Diego we've had several meetings with SDGE at the ground level and they have been responsive to our feedback. In general, SDGE has never obstructed renewable development and has maintained a favorable interpretation of Rule 21 for us where real time monitoring of our existing generation assets are not required. In one of the conversations, they offered to file a Navy specific GO 96 filing if that was our desire. We'll continue to discuss.

We are scheduled to meet with SCE next week. I spoke to Dan Tunnecliff yesterday and he stated that one of their VP's is pressing to get answers on how they can better serve us and they seem to be open to discussions. The bulk of the problems we have had are with SCE's interconnection protocols. Without getting into the weeds, we have had small PV systems locked out by SCE in the past because interconnection procedures weren't followed. Currently at our Navy base in China Lake, we have around 300kw of PV offline until the monitoring issues are resolved. This may come at a very costly investment on our part for communication infrastructure because wireless communication isn't allowed on that base.

That's the summary for now. We have not heard much from the other services other than the Army having problems at Ft. Irwin with SCE's interconnection process. Our Marine Corps installations are experiencing similar pushback from SCE as with the Navy. I'm sure you're aware of the MCLB Barstow legislation.

Once we have this initial meeting with SCE, maybe we can all gather up with both of the utilities. Dan mentioned he was going to be in Sacramento the last week of May to meet CPUC, CEC and Governors office regarding this exact topic. Maybe you're in that meeting. Not sure if anyone from Navy or other services were invited.

We will keep you posted to follow up.

Thank you,

Calvin Kawamura, PE
NAVFAC SW Renewable Program Office
(619) 532-1813

-----Original Message-----
From: Chaset, Nicolas L. [mailto:nicolas.chaset@cpuc.ca.gov]
Sent: Thursday, April 03, 2014 4:51 PM
To: Kawamura, Calvin Y CIV NAVFAC SW
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Calvin
I look forward to hearing from you.
Nick

Nicolas Chaset
Advisor
Office of Commissioner Michael Picker
California Public Utilities Commission
Email: Nicolas.chaset@cpuc.ca.gov
Phone: 510 219 2121

-----Original Message-----
From: Kawamura, Calvin Y CIV NAVFAC SW [mailto:calvin.kawamura@navy.mil]
Sent: Thursday, March 27, 2014 8:48 AM
To: Chaset, Nicolas L.; michael.picker@cpuc.com
Cc: Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Faryan, Marykay CIV N05; Randolph, Edward F.; Randal Friedman; Liotta, Rita M CIV WEST Counsel; Cummins, John M CIV NAVFAC SW
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Nick,
Thank you for your response. We will huddle with the team here, and confer with the Marine Corps and the other services.

We will get back to you shortly.

Regards,

Calvin Kawamura, PE
NAVFAC SW Renewable Program Office
(619) 532-1813

-----Original Message-----
From: Chaset, Nicolas L. [mailto:nicolas.chaset@cpuc.ca.gov]
Sent: Thursday, March 20, 2014 12:58 PM
To: Kawamura, Calvin Y CIV NAVFAC SW; michael.picker@cpuc.com
Cc: Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Faryan, Marykay CIV N05; Randolph, Edward F.; Randal Friedman; Liotta, Rita M CIV WEST Counsel; Cummins, John M CIV NAVFAC SW
Subject: RE: Utility Working Group from ASN/CA Energy Meeting

Calvin
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Once I have everything from you, I will plan a follow up meeting to discuss potential remedies.

Nicolas Chaset
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Email: Nicolas.chaset@cpuc.ca.gov
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Cc: Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Faryan, Marykay CIV N05; Randolph, Edward F.; Randal Friedman; Chaset, Nicolas L.; Liotta, Rita M CIV WEST Counsel; Cummins, John M CIV NAVFAC SW
Subject: Utility Working Group from ASN/CA Energy Meeting

Commissioner Picker,

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Please see attached draft charter for consideration as a framework for moving forward. We request your feedback on our main concerns as summarized in the charter statement and any recommended courses of action. We will be contacting the other services to get their input and appropriate personnel involved in the Working Group.

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We look forward to hearing from you and working with you on this effort. We look to have a follow up meeting or call within the next few weeks to discuss our way forward.

Thank you. Very Respectfully,

Calvin Kawamura, PE
NAVFAC SW Renewable Program Office
(619) 532-1813

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From: Barker, Kevin@Energy [mailto:Kevin.Barker@energy.ca.gov]
Sent: Tuesday, March 04, 2014 6:17 PM
To: Kang, David I CDR OASN (EI&E), ODASN Energy; Griffin, Robert M Jr. SES NAVFAC HQ, ACQ; Forrest, Scott D SES NAVFAC HQ, AM; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Garin, Patrick A I&L; Marrs, Richard L CIV HQMC; Lindsey, Yancy CAPT OASN (EI&E), Executive Assistant to ASN (EI&E); Banaji, Darius CAPT NAVFAC SW; Kliem, John CAPT CNIC HQ, N44; Páez, Bryon J CIV OASN (EI&E), ODASN Energy; Santiago, Angel L LCDR OPNAV, N46; Coleman, Andre L CDR OASN (EI&E), OPDASN EI&E; Hilley, Ryan CIV OASN (EI&E), ODASN Energy; Heckmann, John V CAPT NAVFAC HQ, OPS; Wolfe, Steven R CIV MCI WEST FACILITIES, MCIWEST; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Autry, Keith CAPT OASN (EI&E), OPDASN EI&E; Donovan, Kathryn A CAPT NAVFAC HQ, PW; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Landers, Lynn M CIV HQMC, MCICOM G3/5/7; Clark, Gordon E CIV NAVFAC HQ, AM; Bordelon, Matthew CIV I&L, CL (LFL); Wainwright, Ben V LCDR OASN (EI&E), Military Aide to ASN EI&E; Morin, Kara L CIV MCIWEST-MCB CAMPEN CG STAFF, SSEC; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Ward, Thomas W Col MCIWEST/MCB CAMPEN G3 Operations & Training, AC/S MCIWEST/MCB CAMPEN G-3 Operations & Training; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Christman, Patrick L CIV MCI WEST WREC, WREC; Lyon, Eric M Maj MCBPAC, WACO; Norquist, Stanley W CIV MCIWEST-MCBCP, Environmental Security; Pearcy, Ralph E CIV MARFORPAC, WACO; Thelin, Richard W CIV MARFORPAC, WACO; Carretti, John M CIV AC/S O&T, TRMD; White, Phillip A CIV MCI WEST Facilities Division, MCI WEST G-4(I&L); Gilleskie, Robert J CIV MCI WEST G-4, MCI WEST G-4; McKinley CIV Ned; Wenderoth, Stephen Civ, Counsel for CMC; Lundstrom, Thomas J CIV OASN (EI&E), OAGC EI&E; Hector, Jermaine N CIV NAVFAC HQ, ACQ; dslayton@stanford.edu; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Shwisberg, Lauren CIV PEO SHIPS, PMS325; Morin, Kara L CIV MCIWEST-MCB CAMPEN CG STAFF, SSEC; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Ward, Thomas W Col MCIWEST/MCB CAMPEN G3 Operations & Training, AC/S MCIWEST/MCB CAMPEN G-3 Operations & Training; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Christman, Patrick L CIV MCI WEST WREC, WREC; Lyon, Eric M Maj MCBPAC, WACO; Norquist, Stanley W CIV MCIWEST-MCBCP, Environmental Security; Pearcy, Ralph E CIV MARFORPAC, WACO; Thelin, Richard W CIV MARFORPAC, WACO; Carretti, John M CIV AC/S O&T, TRMD; White, Phillip A CIV MCI WEST Facilities Division, MCI WEST G-4(I&L); Gilleskie, Robert J CIV MCI WEST G-4, MCI WEST G-4; McKinley CIV Ned; Lorge, Patrick RADM CNRSW, N00; Banaji, Darius CAPT NAVFAC SW; Bixler, David B CIV

NAVFAC SW; Roberts, Yvonne CDR NAVFAC SW, FISD; Merrill, Reid K CIV NAVFAC SW, FISD; Haskett, Christopher CIV NAVFAC SW, ESWD; Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Kawamura, Calvin Y CIV NAVFAC SW; Faryan, Marykay CIV N05; Garin, Patrick A I&L; Orndorff, Ryan CIV I&L, LFL; Heinrichs, David A CIV HQMC, HQMC LFF; Forrest, Scott D SES NAVFAC HQ, AM; MF1@cpuc.ca.gov; Nichols, Mary D. @ARB; Oglesby, Rob@Energy; Weisenmiller, Robert@Energy; edward.randolph@cpuc.ca.gov; Scott, Janea@Energy; james.bartridge@energy.ca.gov; Gibbs, Michael@ARB; mpo@cpuc.ca.gov; sberberich@caiso.com; nmillar@caiso.com; ppettingill@caiso.com; michael.picker@cpuc.com; Gravely, Mike@Energy; wade.crowfoot@gov.ca.gov; dslayton@stanford.edu; Bevan, Analisa@ARB
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Subject: RE: SONGS Meeting - Draft minutes

Thank you, David and team for pulling these minutes together. The minutes accurately reflect the topics discussed at the meeting in a very concise fashion.

I wanted to quickly respond to the two pieces of information from the state side regarding the working groups.

1. SONGS working group - CAISO Co-chair identified was Phil Pettingill. His email contact is ppettingill@caiso.com.
2. Transportation pilot - Annalisa Bevan (CARB) Her email contact is abevan@arb.ca.gov

Further, I also wanted to reiterate that the co-chairs for the 6 working groups should reach out to the other agencies to establish the larger working group that will be tackling the issues. The co-chairs should not feel the need to work through identified issues only amongst themselves, in fact other agencies and staff may be critical on a specific topic.

I would also like to instill some sense of urgency to establish the working groups soon. The one month update from the meeting in San Diego is coming up in a few weeks.

I will follow up with David with a monthly update template and we can circulate that with the group.

Best Regards,

Kevin

Kevin M. Barker, Chief of Staff to
Chair Robert B. Weisenmiller
California Energy Commission
(916) 651-6176
1516 Ninth Street MS-33
Sacramento, CA 95814
kevin.barker@energy.ca.gov

-----Original Message-----
From: Kang, David I CDR OASN (EI&E), ODASN Energy [mailto:david.kang@navy.mil]
Sent: Tuesday, March 04, 2014 1:17 PM
To: Barker, Kevin@Energy; Griffin, Robert M Jr. SES NAVFAC HQ, ACQ; Forrest, Scott D SES NAVFAC HQ, AM; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Garin, Patrick A I&L; Marrs, Richard L CIV HQMC; Lindsey, Yancy CAPT OASN (EI&E), Executive Assistant to ASN (EI&E); Banaji, Darius CAPT NAVFAC SW; Kliem, John CAPT CNIC HQ, N44; Páez, Bryon J CIV OASN (EI&E), ODASN Energy; Santiago, Angel L LCDR OPNAV, N46; Coleman, Andre L CDR OASN (EI&E), OPDASN EI&E; Hilley, Ryan CIV OASN (EI&E), ODASN Energy; Heckmann, John V CAPT NAVFAC HQ, OPS; Wolfe, Steven R CIV MCI WEST FACILITIES, MCIWEST; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Autry, Keith CAPT

OASN (EI&E), OPDASN EI&E; Donovan, Kathryn A CAPT NAVFAC HQ, PW; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Landers, Lynn M CIV HQMC, MCICOM G3/5/7; Clark, Gordon E CIV NAVFAC HQ, AM; Bordelon, Matthew CIV I&L, CL (LFL); Wainwright, Ben V LCDR OASN (EI&E), Military Aide to ASN EI&E; Morin, Kara L CIV MCIWEST-MCB CAMPEN CG STAFF, SSEC; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Ward, Thomas W Col MCIWEST/MCB CAMPEN G3 Operations & Training, AC/S MCIWEST/MCB CAMPEN G-3 Operations & Training; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Christman, Patrick L CIV MCI WEST WREC, WREC; Lyon, Eric M Maj MCBPAC, WACO; Norquist, Stanley W CIV MCIWEST-MCBCP, Environmental Security; Pearcy, Ralph E CIV MARFORPAC, WACO; Thelin, Richard W CIV MARFORPAC, WACO; Carretti, John M CIV AC/S O&T, TRMD; White, Phillip A CIV MCI WEST Facilities Division, MCI WEST G-4(I&L); Gilleskie, Robert J CIV MCI WEST G-4, MCI WEST G-4; McKinley CIV Ned; Wenderoth, Stephen Civ, Counsel for CMC; Lundstrom, Thomas J CIV OASN (EI&E), OAGC EI&E; Hector, Jermaine N CIV NAVFAC HQ, ACQ; dslayton@stanford.edu; Omans, James D CIV OASN (EI&E), OPDASN EI&E; Lombardo, Ralph CIV OASN (EI&E), AGC; Shwisberg, Lauren CIV PEO SHIPS, PMS325; Morin, Kara L CIV MCIWEST-MCB CAMPEN CG STAFF, SSEC; Reuning, Charles R CAPT AC/S FAC, MCI WEST FACILITIES; Ward, Thomas W Col MCIWEST/MCB CAMPEN G3 Operations & Training, AC/S MCIWEST/MCB CAMPEN G-3 Operations & Training; Jarvis, David K LtCol AC/S Facilities/Ops, AC/S Facilities/Ops; Christman, Patrick L CIV MCI WEST WREC, WREC; Lyon, Eric M Maj MCBPAC, WACO; Norquist, Stanley W CIV MCIWEST-MCBCP, Environmental Security; Pearcy, Ralph E CIV MARFORPAC, WACO; Thelin, Richard W CIV MARFORPAC, WACO; Carretti, John M CIV AC/S O&T, TRMD; White, Phillip A CIV MCI WEST Facilities Division, MCI WEST G-4(I&L); Gilleskie, Robert J CIV MCI WEST G-4, MCI WEST G-4; McKinley CIV Ned; Lorge, Patrick RADM CNRSW, N00; Banaji, Darius CAPT NAVFAC SW; Bixler, David B CIV NAVFAC SW; Roberts, Yvonne CDR NAVFAC SW, FISD; Merrill, Reid K CIV NAVFAC SW, FISD; Haskett, Christopher CIV NAVFAC SW, ESWD; Parry, Christopher F CIV NAVFACSW, swopmd; Lindsey, Bernard J CIV NAVFAC SW; Kawamura, Calvin Y CIV NAVFAC SW; Faryan, Marykay CIV N05; Garin, Patrick A I&L; Orndorff, Ryan CIV I&L, LFL; Heinrichs, David A CIV HQMC, HQMC LFF; Forrest, Scott D SES NAVFAC HQ, AM; MF1@cpuc.ca.gov; Nichols, Mary D. @ARB; Oglesby, Rob@Energy; Barker, Kevin@Energy; Weisenmiller, Robert@Energy; edward.randolph@cpuc.ca.gov; Scott, Janea@Energy; james.bartridge@energy.ca.gov; Gibbs, Michael@ARB; mpo@cpuc.ca.gov; sberberich@caiso.com; nmillar@caiso.com; ppettingill@caiso.com; michael.picker@cpuc.com; Gravely, Mike@Energy; wade.crowfoot@gov.ca.gov; dslayton@stanford.edu
Cc: Shwisberg, Lauren CIV PEO SHIPS, PMS325; Coleman, Andre L CDR OASN (EI&E), OPDASN EI&E; Stites, Alex D CAPT NAVFAC Washington, OPS; McGinn, Dennis V HON ASN (EI&E)
Subject: SONGS Meeting - Draft minutes

Kevin/DON Team, please review the minutes of the SONGS meeting and provide any comments or changes. Please use track changes for any revisions and send to me COB, Tuesday, 11 Mar.

We have listed the six working groups identified during our meeting. Please verify co-chairs for those working groups from NAVFAC SW, MCIWEST, and State agencies. I am missing the following info for co-chairs:

1. SONGS working group - CAISO Co-chair name/contact info.
2. Transportation pilot - Need contact info for Annalisa Bevan (CARB) 3. Transportation pilot - Need MCIWEST POC

ASN McGinn and Dr. Weisenmiller will be holding monthly progress updates via phonecon. Additional information will be provided to the working group chairs to outline expectations for monthly updates/progress with their working groups and the issues/opportunities that have been identified.

Please let me know if you have any questions.

Very Respectfully,

David Kang, P.E.
CDR, CEC, USN
Director for Shore Energy
Office of the Deputy Assistant Secretary of the Navy for Energy

1000 Navy Pentagon, RM 5E157
Washington DC 20350-1000
Phone: (571) 256-9152
Cell: (703) 980-7662
SIPR: david.kang@navy.smil.mil

Tab 47

Message

From: Randolph, Edward F. [edward.randolph@cpuc.ca.gov]
Sent: 5/20/2014 1:07:30 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Subject: Fwd: Subject for Randolph/Picker/Weisenmiller call
Attachments: image001.gif

Below is the topic for the call Weisenmiller was trying to set up with us.

Karen and I had a little bit of a heated back and forth on this issue last week after the EP meeting and I assumed she would go to someone to complain about ED and put the burden on us. It looks like it was Weisenmiller.

First, Karen and I talked about this yesterday and have a plan for filing in the data they need. Based on what I know, the missing information does not impact the CEC's contingency plan work and Cynthia has been working separately with the CEC staff to make sure that work is going as close to hand-in-glove as possible, but I want to check in with Cynthia to make sure there is not a development from this week I am not aware of.

So I think I can resolve the need for a call with an email later today that spells out what is going on.

For background: The issue really is that the ISO wants dates in the tracking system that we don't know yet since some of the timelines and numbers are subject to what types of resources come out of the all source procurements. I have become increasingly cautious with the CAISO since "subject to change" doesn't mean much to them. In the past numbers we all agreed were not real and were put in documents as a starting point of conversation became the "real" numbers to them despite what actual analysis pointed to (even their own). To deal with the unknown issues ED had suggested we focus on the big milestones dates where big decision need to be made and we can fill in some of the progress dates as we see actually details as we get them.

I have to admit that working with Karen is getting old. At some point I will rant in person.

Begin forwarded message:

> **From:** "Cross, Catherine@Energy" <Catherine.Cross@energy.ca.gov>
> **Date:** May 20, 2014 at 11:47:22 AM PDT
> **To:** "doris.lo@cpuc.ca.gov" <doris.lo@cpuc.ca.gov>
> **Cc:** "Randolph, Edward F." <edward.randolph@cpuc.ca.gov>
> **Subject: Subject for Randolph/Picker/Weisenmiller call**
>
> **See below**
>
> ---
>
> **From:** Weisenmiller, Robert@Energy
> **Sent:** Tuesday, May 20, 2014 9:15 AM
> **To:** Michael Picker
> **Cc:** Cross, Catherine@Energy
> **Subject:** Re: Picker can't remember reason for call w/Randolph!

Trying to get ED to work with ISO (and CEC). staff to fill in tracking system so we can decide when to launch contingencies in the songs context. Once picker went to cpuc. ... Peevey told me to talk to you and ed. Bob

Sent from my iPhone

On May 20, 2014, at 12:08 PM, "Cross, Catherine@Energy" <Catherine.Cross@energy.ca.gov> wrote:

> <image001.gif>
> (and I never had a subject) figured you'd remember!
>
> ***Catherine Lahey Cross***
> *Administrative Assistant to*
> *Chair Robert B. Weisenmiller*
> California Energy Commission
> catherine.cross@energy.ca.gov
> (916) 654-5036

Tab 48

_

From: Picker, Michael <Michael.Picker@cpuc.ca.gov>
Sent: Tuesday, May 20, 2014 2:26 PM
To: Randolph, Edward F.
Subject: RE: Subject for Randolph/Picker/Weisenmiller call

Beer discussion.

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: Randolph, Edward F.
Sent: Tuesday, May 20, 2014 1:08 PM
To: Picker, Michael
Subject: Fwd: Subject for Randolph/Picker/Weisenmiller call

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> California Energy Commission
> catherine.cross@energy.ca.gov
> (916) 654-5036

Tab 49

From: Randolph, Edward F. <edward.randolph@cpuc.ca.gov>
Sent: Tuesday, May 20, 2014 2:38 PM
To: Picker, Michael
Subject: Re: Subject for Randolph/Picker/Weisenmiller call

The whole thing or the rant?

Sent from a "smartphone" which helps us communicate but makes us illiterate.
Edward Randolph

On May 20, 2014, at 2:26 PM, "Picker, Michael" <Michael.Picker@cpuc.ca.gov> wrote:

> Beer discussion.
>
> 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:** Randolph, Edward F.
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Tab 50

From: Picker, Michael <Michael.Picker@cpuc.ca.gov>
Sent: Tuesday, May 20, 2014 2:54 PM
To: Randolph, Edward F.
Subject: RE: Subject for Randolph/Picker/Weisenmiller call

Rants take more beer to parse through.

Commissioner Michael Picker
California Public Utilities Commission
505 Van Ness, Fifth Floor
San Francisco, CA 94102
(415) 703-2444
Michael.Picker@cpuc.ca.gov

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> *Chair Robert B. Weisenmiller*
> California Energy Commission
> catherine.cross@energy.ca.gov
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Tab 51

From: Randolph, Edward F. <edward.randolph@cpuc.ca.gov>
Sent: Tuesday, May 20, 2014 6:59 PM
To: Weisenmiller, Robert@Energy (Robert.Weisenmiller@energy.ca.gov); Picker, Michael
Subject: tracking milestones for the So Cal Reliablity Project

I am not sure if the meeting that is on my schedule with the two of you is actually still happening but based on what I was told is the subject I don't know that it is really needed. The originally time it was scheduled conflicts with a meeting I have with Commissioner Florio on a subject that needs to be resolved this week.

My understanding is that Commissioner Weisenmiller would like to make sure ED is getting the ISO what they need for the project management documents so that all the agencies know the key milestones we need to track and how procurement would impact contingency plans. There has been some tension in pulling these information together and the issue really boils down to the fact that there are few milestones that we don't know the exact timing of yet and the staff that would be able to figure this out are focused on the actual work needed to meet these milestones.

I admittedly got a little testy with Karen Edson last week on this issue as I felt the ISO was trying to micromanage my staff, but I also gave the ISO a road map at that point that I thought would help me get them the data they wanted and I talked with Karen Edson about this issue since then and the ISO will provide us a more focused list of what is needed now. I think the holes can be filled in shortly. To the extent that any holes directly impact the CEC's efforts to develop the contingency plans document, I will make sure my folks work with the CEC staff to make sure we give priority to what they need.

This project is clearly of vital importance to Energy Division and I don't think anyone here is giving it less than 100% of the attention it needs. At this stage in the game a lot of the actual work that needs to be done is with the CPUC. In the past few months we have had approved Pio Pico, have approved the procurement authorization in track 4 of the LTPP proceeding, have been working with SCE on the procurement authorizations from track 1, are now working on reviewing the procurement plans for SDG&E, have opened the next LTPP proceeding and started modeling and assumptions work for that proceeding, and are adopting new rules for flexible RA. I am sure this list misses a few other things we are doing that directly relate to the long term issues dealing with the loss of SONGS and it likely under sells the time involved in a few of these issues. It also does not include other issues that indirectly impact reliability in the region such as developing a new integration adders for the RPS program, the analysis that is underway at ED for the post 2030 needs, and the work on the future of NEM and rate reform.

Edward Randolph | Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue, Room 4004
San Francisco, CA, 94102
415-703-2083 | edward.randolph@cpuc.ca.gov

Tab 52

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From: Weisenmiller, Robert@Energy <Robert.Weisenmiller@energy.ca.gov>
Sent: Wednesday, May 21, 2014 11:50 AM
To: Randolph, Edward F.; Picker, Michael
Subject: RE: tracking milestones for the So Cal Reliablity Project

Ed – Thanks for the bringing your concerns to my attention. Obviously, I don't want to interfere with your Commissioner Florio meeting, but I am sure you will want to follow-up on Peevey's directions to me.

When I last met with Peevey I raised two issues with him. He pointed to you on both, but included Picker on one.

Dealing with the "Ed only" issue first, I asked Peevey when the EMV reports were going to be released so they can be factored into the next IEPR forecast update. He said to ask you, so when?

On the SoCal issues I told Peevey it seemed from my review of my staff's materials it appeared that the tracking work had gone on a stall with Picker's appointment to the CPUC. I pulled an update from the last EP meeting but it is getting to be time. Peevey told me to talk to you and Picker at the same time so we both have the benefit to Picker's vision.

As a first step let's pin down the timelines for the conventional resources. (Not to ignore the preferred stuff but I am sure it will take more time to develop the timelines so let's start with the "easy" items to track.)

Specifically, on Pio Pico – any timelines for any legal challenges in terms of CPUC reconsideration or judicial review?

On Sycamore- Penasquitos 230 kV line – timeline for application, steps in CPCN, decision?

Timelines for any other transmission infrastructure that is SONGs related in the SDG&E or SCE areas, such as Static Var Compensators, etc.

On SDG&E's Carlsbad ppa – timeline for application and decision

Expected timelines for SCE compliance with the two LTPP decisions in terms of the acquisition of conventional generation resources?

When should I expect this first tranche of material?

Bob

Ps. From my ARRA days I can tell you that Picker is pretty insistent on detailed project work plans, which as a manager were great for accountability and delivering results.

From: Randolph, Edward F. [mailto:edward.randolph@cpuc.ca.gov]
Sent: Tuesday, May 20, 2014 6:59 PM
To: Weisenmiller, Robert@Energy; Picker, Michael
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Edward Randolph | Director, Energy Division
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San Francisco, CA, 94102
415-703-2083 | edward.randolph@cpuc.ca.gov

Tab 53

Message

From: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Sent: 5/22/2014 7:32:55 AM
To: Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Subject: FW: tracking milestones for the So Cal Reliablity Project

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From: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
Sent: Wednesday, May 21, 2014 11:50 AM
To: Randolph, Edward F.; Picker, Michael
Subject: RE: tracking milestones for the So Cal Reliablity Project

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When should I expect this first tranche of material?

Bob

Ps. From my ARRA days I can tell you that Picker is pretty insistent on detailed project work plans, which as a manager were great for accountability and delivering results.

From: Randolph, Edward F. [mailto:edward.randolph@cpuc.ca.gov]
Sent: Tuesday, May 20, 2014 6:59 PM
To: Weisenmiller, Robert@Energy; Picker, Michael
Subject: tracking milestones for the So Cal Reliablity Project

I am not sure if the meeting that is on my schedule with the two of you is actually still happening but based on what I was told is the subject I don't know that it is really needed. The originally time it was scheduled conflicts with a meeting I have with Commissioner Florio on a subject that needs to be resolved this week.

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Edward Randolph | Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue, Room 4004
San Francisco, CA, 94102
415-703-2083 | edward.randolph@cpuc.ca.gov<mailto:p@cpuc.ca.gov>

Tab 54

From: Randolph, Edward F. <edward.randolph@cpuc.ca.gov>
Sent: Thursday, May 22, 2014 6:08 PM
To: Weisenmiller, Robert@Energy; Picker, Michael
Subject: RE: tracking milestones for the So Cal Reliablity Project

Thank you.

At one point the call for today had been rescheduled for Friday, but now it looks like that is not happening either. We will work to get all the data you have asked for filled in ASAP and I will provide you with an email with most of the details tomorrow (or maybe Saturday since I am on a long plane ride tomorrow night). There are a few gaps that we need to talk in person about since there are legal reason why we need to be careful about what we say, but I can tell you those items have a very high priority and are being watched closely.

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Finally, for both of you, I understand the need for detailed work plans and know that approach was critical to getting the ARRA projects done. One thing about the ARRA process is you started out with a firm date when construction needed to start and you could work backwards from there to build the timelines. It seems to me that in this case everyone is waiting on the CPUC to work forward and say when we can complete our proceedings as the starting point to building the work plans. Throughout this this process I have been asking to know the date in which the Cal ISO needs to know the project are real so that I can work backwards to build our work plans. It would be much easier for me to work backwards. The problem with working forward is that with all the herding of cats it takes to move things at the CPUC I don't have a good tool to get the parts of the Commission I don't control (which is almost all of it) to commit to anything unless I can get them to focus a work plan. The best tool I have is to be able to say, we need to do X by a specific date, then I can get people's attention.

Edward Randolph | Phone: 415-703-2083 | Cell: 916-601-9635

From: Weisenmiller, Robert@Energy [mailto:Robert.Weisenmiller@energy.ca.gov]
Sent: Wednesday, May 21, 2014 11:50 AM
To: Randolph, Edward F.; Picker, Michael
Subject: RE: tracking milestones for the So Cal Reliablity Project

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Edward Randolph | Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue, Room 4004
San Francisco, CA, 94102
415-703-2083 | edward.randolph@cpuc.ca.gov

Tab 55

Message

From: Banks, Juliane [juliane.banks@cpuc.ca.gov]
Sent: 5/27/2014 2:35:07 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]; Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Subject: FW: 6/17/14 California Reliability/SONGS Meeting in Los Angeles
Attachments: image001.gif

Hi Michael,

Here's some information about the meeting at Peevey's house...

Juliane
415-703-2284

From: Cross, Catherine@Energy
Sent: Tuesday, May 27, 2014 12:21 PM
To: Juliane Banks
Subject: FW: California Reliability/SONGS Dinner in Los Angeles

Hi Juliane:

Hope this helps! (Cliff Rechtschaffen was substituted for Wade Crowfoot.) Felicia Marcus is the only person on list that can't attend.

President Peevey's address and cell #:

1322 Verdugo Blvd.
La Canada Flintridge, CA 91011
Cell: 415-613-4919

Chair Weisenmiller's meeting @ SCE in Rosemead ends @ 2 pm. Does Commissioner Picker need a ride to President Peevey's house?

(This info came from another email: The CEPRD meeting is being held at the SCE building in Los Angeles and President Peevey's home is approximately thirty minutes away. His home is approximately twenty minutes from the Burbank/Bob Hope Airport. We don't have an exact time for the meeting @ President Peevey's home – probably 3 pm given the traffic between SCE and his home. Chair Weisenmiller is booked on SW Flight 2152 departing Burbank at 6:10 pm and arriving in Sacramento at 7:20 pm.)

From: Cross, Catherine@Energy
Sent: Friday, April 25, 2014 12:27 PM
To: Darlene Stasky (dstasky@caiso.com); (Elizabeth.Norvell@GOV.CA.GOV); (Alicia.Barrios@waterboards.ca.gov); Shannon Stewart; Nuria Gonzalez; Lorton, Michele@Energy; Denise Whitcher (dwhitcher@aqmd.gov)
Cc: Steve Berberich; Wade Crowfoot (wade.crowfoot@gov.ca.gov); Marcus, Felicia@Waterboards (Felicia.Marcus@waterboards.ca.gov); Nichols, Mary D. @ARB; Michael R. Peevey; Scott, Janea@Energy; Wallerstein Barry (bwallerstein@aqmd.gov)
Subject: California Reliability/SONGS Dinner in Los Angeles

Chair Weisenmiller would like to have a dinner meeting on Monday, June 16, 2014, in Los Angeles to discuss California Reliability/SONGS. Please check availability and get back to me as soon as possible. (I believe a number of your principals will be in Los Angeles to attend a meeting the next morning.)

Sincerely,

Catherine
Catherine Lahey Cross
Administrative Assistant to
Chair Robert B. Weisenmiller
California Energy Commission
catherine.cross@energy.ca.gov
(916) 654-5036

Tab 56

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From: Weisenmiller, Robert@Energy <Robert.Weisenmiller@energy.ca.gov>
Sent: Thursday, May 29, 2014 8:44 AM
To: Randolph, Edward F.; Picker, Michael
Subject: RE: tracking milestones for the So Cal Reliablity Project

Ed

Hope the long plane flight went smoothly, although I assume that means a long plane back.

Part of working back is easy. Carlsbad is the next important OTC unit. Felicia was fairly clear that we should plan on building any otc extension request into the April energy filing with the water board. So April 2016 with some months to prepare the filing. So December of 2015 is when I need regulatory actions to be completed and construction under way.

LA stuff is later but requires a lot more to happen.

Sooner the better for EMF data so all the IEPR stakeholders can really dig into its implications.

Bob

From: Randolph, Edward F. [mailto:edward.randolph@cpuc.ca.gov]
Sent: Thursday, May 22, 2014 6:08 PM
To: Weisenmiller, Robert@Energy; Picker, Michael
Subject: RE: tracking milestones for the So Cal Reliablity Project

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505 Van Ness Avenue, Room 4004
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Tab 59

Message

From: Marcus, Felicia@Waterboards [Felicia.Marcus@waterboards.ca.gov]
Sent: 5/30/2014 6:38:06 PM
To: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
CC: 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]; Stewart, Shannon@ARB [snstewar@arb.ca.gov]; Lorton, Michele@Energy [michele.lorton@energy.ca.gov]; Darlene Stasky (dstasky@caiso.com) [dstasky@caiso.com]; Kim Hubner [KHubner@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]
Subject: Re: SONGS/California Reliability Meeting

Sorry to miss you, but I'll be chairing our Board meeting and Jon and Fran have to be there too.
Would love a catch up call after!

Sent from my iPad

On May 30, 2014, at 3:51 PM, "Weisenmiller, Robert@Energy" <Robert.Weisenmiller@energy.ca.gov> wrote:

> When: Tuesday, June 17, 2014 3:00 PM-4:15 PM (GMT-08:00) Pacific Time (US & Canada).
> Where: Mary Nichols' Residence, 435 South Irving Boulevard, Los Angeles, CA 90020, (323) 930-1619
>
> Note: The GMT offset above does not reflect daylight saving time adjustments.
>
> *~*~*~*~*~*~*~*~*~*
>
> Meeting will commence at approximately 3:00 pm at Mary Nichol's residence (located approximately 30 minutes from Burbank/Bob Hope Airport)
>
> Google map from Burbank Airport to 435 So Irving Blvd.: http://goo.gl/maps/4RaKP
> Google map from 435 So. Irving Blvd. to Burbank Airport: http://goo.gl/maps/ZB7r6
>
> After meeting:
>
> Traveling from Burbank to Sacramento:
> Southwest Flight 2152 departs Burbank @ 6:10 pm/arrives Sacramento 7:20 pm
>
> Traveling from Burbank to Oakland:
> Southwest Flight 4763 departs Burbank @ 6:55 pm/arrives Oakland 8:05 pm
>
> Participants:
>
> Air Resources Board
> Mary Nichols
>
> California Energy Commission
> 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)

>
> <SONGS_California Reliability Meeting>

Tab 60

Message

From: Turner, Brian [Brian.Turner@cpuc.ca.gov]
Sent: 6/10/2014 1:56:18 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]; Peevey, Michael R. [michael.peevey@cpuc.ca.gov]
Subject: Energy principals meeting

ARB is asking if we have anything else for the agenda at next Tuesday's meeting at Mary's house.
Agenda is primarily SONGS/South Coast reliability and E3 2030 policy work.
Is Germany read-out ready? Anything else?
Also, Ed Randolph is planning to go down to participate in the SONGS discussion, but we're not planning on any other PUC presence.
Thanks

Brian Turner
Deputy Executive Director for Policy and External Relations
California Public Utilities Commission
415-589-1118 (cell)
415-703-5765 (desk)
Brian.Turner@cpuc.ca.gov

Tab 61

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From: Picker, Michael <Michael.Picker@cpuc.ca.gov>
Sent: Tuesday, June 10, 2014 1:57 PM
To: Turner, Brian
Subject: RE: Energy principals meeting

I'll be there.

Michael Picker
California Public Utilities Commission
(415) 703-2444

From: Turner, Brian
Sent: Tuesday, June 10, 2014 1:56 PM
To: Picker, Michael; Peevey, Michael R.
Subject: Energy principals meeting

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Deputy Executive Director for Policy and External Relations
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415-589-1118 (cell)

415-703-5765 (desk)
Brian.Turner@cpuc.ca.gov

Tab 65

Message

From: Weisenmiller, Robert@Energy [Robert.Weisenmiller@energy.ca.gov]
Sent: 7/25/2014 3:10:50 PM
To: McCarthy, Ryan@ARB [ryan.mccarthy@arb.ca.gov]
CC: Rechtschaffen, Cliff [cliff.rechtschaffen@gov.ca.gov]; Mike Rossi (mike.rossi@gov.ca.gov) [mike.rossi@gov.ca.gov]; Nichols, Mary D. @ARB [mary.nichols@arb.ca.gov]; Corey, Richard@ARB [rcorey@arb.ca.gov]; Turner, Brian [Brian.Turner@cpuc.ca.gov]; Edson, Karen (KEdson@caiso.com) [KEdson@caiso.com]; michael.picker@cpuc.ca.gov; Marcus, Felicia@Waterboards [Felicia.Marcus@waterboards.ca.gov]; Gibbs, Michael@ARB [mgibbs@arb.ca.gov]; Stewart, Shannon@ARB [snstewar@arb.ca.gov]
Subject: Re: August Energy Principal items

Since aug 2O iepr is songs it would be useful to have an update on the tracking system.

Presentations are at a higher level.

Bob

Sent from my iPhone

On Jul 25, 2014, at 3:04 PM, "ryan.mccarthy@arb.ca.gov" <ryan.mccarthy@arb.ca.gov> wrote:

> Hi all,
>
> I want to touch base regarding the August Energy Principals meeting..
>
> We'll have E3 there to work through the proposed scenarios, which I believe they will share and discuss with you all beforehand. (Nancy is on vacation that week, so it will probably be Amber from E3.) I figure we should leave an hour for that, and it may not take that long.
>
> Also probably have shorter items on August 20 IEPR meeting prep and the usual 111(d) touch base.
>
> Are there other items you would like to cover? SONGS? Legislative update? Centralized energy data portal? Anything else?
>
> September's meeting will be in San Francisco and possibly almost entirely focused on reviewing initial scenario results from E3, so any topic of too much substance that is not covered in August may have to wait until October.
>
> Also, I'd like to begin working to find a time for the Principals to meet with SoCal utilities to discuss role of natural gas in our mid- and long-term energy planning and policies. It's possible we could try to make it happen as part of the August Energy Principals meeting, but that will probably be pretty tight, unless we're only talking E3 scenarios. Otherwise, I'll work with Shannon and your schedulers to try to find a time in the next month or two that works for that meeting. I think we'd want to set aside at least two hours in Sacramento for that discussion.
>
> Thanks,
> Ryan
>
> Ryan McCarthy, PhD
> Science and Technology Policy Advisor
> Office of the Chair
> California Air Resources Board
> (916) 323-2602 (office)

(916) 217-4714 (cell)

Tab 66

—

From: Randolph, Edward F. <edward.randolph@cpuc.ca.gov>
Sent: Tuesday, July 29, 2014 2:01 PM
To: Jaske, Mike@Energy; Pettingill, Phil; Walker, Cynthia; Kelley, Kristen; Van Pelt, Gregory; Barker, Kevin@Energy; Picker, Michael; Tollstrup, Michael@ARB; Bohan, Drew@Energy; Oglesby, Rob@Energy; Kato, Stephanie@ARB; Drew, Tim G.; Bender, Sylvia@Energy
Cc: Edson, Karen; Rechtschaffen, Cliff; Bender, Sylvia@Energy; Barker, Kevin@Energy
Subject: RE: Agency Reliability Planning

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Edward Randolph | Phone: 415-703-2083 | Cell: 916-601-9635

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Sent: Tuesday, July 29, 2014 11:01 AM
To: Pettingill, Phil; Walker, Cynthia; Kelley, Kristen; Van Pelt, Gregory; Randolph, Edward F.; Barker, Kevin@Energy; Picker, Michael; Tollstrup, Michael@ARB; Bohan, Drew@Energy; Oglesby, Rob@Energy; Kato, Stephanie@ARB; Drew, Tim G.; Bender, Sylvia@Energy
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I have two questions:

1. Why wouldn't we discuss Cynthia's proposal at the in person meeting Thursday morning?
2. Do we need a separate bi-weekly call?

Mike

From: Pettingill, Phil [mailto:PPettingill@caiso.com]
Sent: Tuesday, July 29, 2014 10:31 AM
To: Walker, Cynthia; Kelley, Kristen; Van Pelt, Gregory; Randolph, Edward; Barker, Kevin@Energy; Picker, Michael; Tollstrup, Michael@ARB; Bohan, Drew@Energy; Oglesby, Rob@Energy; Kato, Stephanie@ARB; Drew, Tim G.; Bender, Sylvia@Energy; Jaske, Mike@Energy
Cc: Edson, Karen; Rechtschaffen, Cliff; Bender, Sylvia@Energy; Randolph, Edward; Barker, Kevin@Energy
Subject: RE: Agency Reliability Planning

Cynthia

Thank you for helping to clarify your thinking.

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As I recall, this was something like 1,600MWs that was assumed but did not have an authorization.

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Phil Pettingill
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916-608-7241

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Sent: Tuesday, July 29, 2014 8:55 AM
To: Kelley, Kristen; Van Pelt, Gregory; Randolph, Edward; Pettingill, Phil; Kevin Barker; Picker, Michael; 'Tollstrup, Michael@ARB (mtollstr@arb.ca.gov)'; 'Drew.Bohan@energy.ca.gov'; 'Oglesby, Rob@Energy (Rob.Oglesby@energy.ca.gov)'; 'Kato, Stephanie@ARB'; Drew, Tim G.; Bender Sylvia; Jaske, Mike@Energy (Mike.Jaske@energy.ca.gov)
Cc: Edson, Karen; Rechtschaffen, Cliff; 'Bender, Sylvia@Energy'; Randolph, Edward; Kevin Barker
Subject: RE: Agency Reliability Planning

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Deputy Director
Energy Division
California Public Utilities Commission
ciw@cpuc.ca.gov
415.703.1836
415.806.0488 (cell)
www.cpuc.ca.gov

Tab 67

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From: Walker, Cynthia <cynthia.walker@cpuc.ca.gov>
Sent: Tuesday, July 29, 2014 2:05 PM
To: Randolph, Edward F.; Jaske, Mike@Energy; Pettingill, Phil; Kelley, Kristen; Van Pelt, Gregory; Barker, Kevin@Energy; Picker, Michael; Tollstrup, Michael@ARB; Bohan, Drew@Energy; Oglesby, Rob@Energy; Kato, Stephanie@ARB; Drew, Tim G.; Bender, Sylvia@Energy
Cc: Edson, Karen; Rechtschaffen, Cliff; Bender, Sylvia@Energy; Barker, Kevin@Energy
Subject: RE: Agency Reliability Planning

So we should make sure we have time to discuss this during our regular agency call, not the morning session. Drew and Mike, I am not coming to Sacramento so Ed, Tim and I will call in to the morning meeting as well. I apologize but have some other things I need to do that day and need to be here to get them done.

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Cc: Edson, Karen; Rechtschaffen, Cliff; Bender, Sylvia@Energy; Barker, Kevin@Energy
Subject: RE: Agency Reliability Planning

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Cc: Edson, Karen; Rechtschaffen, Cliff; Bender, Sylvia@Energy; Randolph, Edward F.; Barker, Kevin@Energy
Subject: RE: Agency Reliability Planning

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To: Walker, Cynthia; Kelley, Kristen; Van Pelt, Gregory; Randolph, Edward; Barker, Kevin@Energy; Picker, Michael; Tollstrup, Michael@ARB; Bohan, Drew@Energy; Oglesby, Rob@Energy; Kato, Stephanie@ARB; Drew, Tim G.; Bender, Sylvia@Energy; Jaske, Mike@Energy
Cc: Edson, Karen; Rechtschaffen, Cliff; Bender, Sylvia@Energy; Randolph, Edward; Barker, Kevin@Energy
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To: Kelley, Kristen; Van Pelt, Gregory; Randolph, Edward; Pettingill, Phil; Kevin Barker; Picker, Michael; 'Tollstrup, Michael@ARB (mtollstr@arb.ca.gov)'; 'Drew.Bohan@energy.ca.gov'; 'Oglesby, Rob@Energy (Rob.Oglesby@energy.ca.gov)'; 'Kato, Stephanie@ARB'; Drew, Tim G.; Bender Sylvia; Jaske, Mike@Energy (Mike.Jaske@energy.ca.gov)
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Tab 68

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From: Barker, Kevin@Energy <Kevin.Barker@energy.ca.gov>
Sent: Tuesday, July 29, 2014 3:11 PM
To: Randolph, Edward F.; Jaske, Mike@Energy; Pettingill, Phil; Walker, Cynthia; Kelley, Kristen; Van Pelt, Gregory; Picker, Michael; Tollstrup, Michael@ARB; Bohan, Drew@Energy; Oglesby, Rob@Energy; Kato, Stephanie@ARB; Drew, Tim G.; Bender, Sylvia@Energy
Cc: Edson, Karen; Rechtschaffen, Cliff; Bender, Sylvia@Energy
Subject: RE: Agency Reliability Planning

This is correct, Ed. We currently have two requests for hourly data for subs in SCE and SDG&E territory. They have been helpful thus far.

From: Randolph, Edward F. [mailto:edward.randolph@cpuc.ca.gov]
Sent: Tuesday, July 29, 2014 2:01 PM
To: Jaske, Mike@Energy; Pettingill, Phil; Walker, Cynthia; Kelley, Kristen; Van Pelt, Gregory; Barker, Kevin@Energy; Picker, Michael; Tollstrup, Michael@ARB; Bohan, Drew@Energy; Oglesby, Rob@Energy; Kato, Stephanie@ARB; Drew, Tim G.; Bender, Sylvia@Energy
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Tab 74

From: Picker, Michael <Michael.Picker@cpuc.ca.gov>
Sent: Monday, September 22, 2014 5:09 PM
To: Weisenmiller, Robert@Energy; McCarthy, Ryan@ARB
Cc: Rechtschaffen, Cliff; Mike Rossi (mike.rossi@gov.ca.gov); Nichols, Mary D. @ARB; Corey, Richard@ARB; Turner, Brian; Edson, Karen (KEdson@caiso.com); Picker, Michael; Marcus, Felicia@Waterboards; Gibbs, Michael@ARB; Barker, Kevin@Energy; Stewart, Shannon@ARB
Subject: RE: October Energy Principals items

I don't feel like we need to spend time on the NREL model now.

Sent from my Verizon Wireless 4G LTE smartphone

-------- Original message --------
From: "Weisenmiller, Robert@Energy"
Date:09/22/2014 5:06 PM (GMT-08:00)
To: "McCarthy, Ryan@ARB"
Cc: "Rechtschaffen, Cliff" ,"Mike Rossi (mike.rossi@gov.ca.gov)" ,"Nichols, Mary D. @ARB" ,"Corey, Richard@ARB" ,"Turner, Brian" ,"Edson, Karen (KEdson@caiso.com)" ,"Picker, Michael" ,"Marcus, Felicia@Waterboards" ,"Gibbs, Michael@ARB" ,"Barker, Kevin@Energy" ,"Stewart, Shannon@ARB"

Subject: Re: October Energy Principals items

We need to present drecp at this event.

I am fairly underwhelmed by the CEERT study so don't see any need to give it any ep time this month. Bob

Sent from my iPhone

On Sep 22, 2014, at 2:56 PM, "McCarthy, Ryan@ARB" <ryan.mccarthy@arb.ca.gov> wrote:

> Hi all,
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sector. There has been some suggestion of having them present at the Energy Principals… I think it would be tight for October, but that's probably the time to do it if you all want to hear from them together. Should we pull them in for a short presentation?

Thanks,
Ryan

Tab 75

Message

From: Nichols, Mary D. @ARB [mary.nichols@arb.ca.gov]
Sent: 9/22/2014 5:31:11 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Subject: Re: October Energy Principals items

I am intrigued by Picker and Bob W's quick dismissal of the NREL. What's up with that? I don't know if we need an EP briefing for political reasons, but I am interested in your thoughts.

Sent from my iPhone

On Sep 22, 2014, at 8:09 PM, "Picker, Michael" <Michael.Picker@cpuc.ca.gov> wrote:

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> From: "Weisenmiller, Robert@Energy"
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> To: "McCarthy, Ryan@ARB"
> Cc: "Rechtschaffen, Cliff" ,"Mike Rossi (mike.rossi@gov.ca.gov)" ,"Nichols, Mary D. @ARB" ,"Corey, Richard@ARB" ,"Turner, Brian" ,"Edson, Karen (KEdson@caiso.com)" ,"Picker, Michael" ,"Marcus, Felicia@Waterboards" ,"Gibbs, Michael@ARB" ,"Barker, Kevin@Energy" ,"Stewart, Shannon@ARB"
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Thanks,
Ryan

Tab 76

Message

From: Picker, Michael [Michael.Picker@cpuc.ca.gov]
Sent: 9/22/2014 6:24:58 PM
To: Nichols, Mary D. @ARB [mary.nichols@arb.ca.gov]
Subject: RE: October Energy Principals items

They have not normally excelled at modeling and lots of poorly framed assumptions - we can sell all of our excess generation for example.

Sent from my Verizon Wireless 4G LTE smartphone

-------- Original message --------
From: "Nichols, Mary D. @ARB"
Date:09/22/2014 5:30 PM (GMT-08:00)
To: "Picker, Michael"
Subject: Re: October Energy Principals items

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Tab 77

Message

From: michael.picker@cpuc.ca.gov by E&E Publishing [email_this@eenews.net]
Sent: 11/5/2014 3:18:40 PM
To: michael.picker@cpuc.ca.gov
Subject: From E&ENews PM -- UTILITIES: Distributed energy storage gets big boost in new Calif. contracts

This E&ENews PM story was sent to you by: michael.picker@cpuc.ca.gov

E&ENEWS PM

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UTILITIES:
Distributed energy storage gets big boost in new Calif. contracts

Katherine Ling, E&E reporter

Published: Wednesday, November 5, 2014

Southern California Edison announced contracts today for 260 megawatts of energy storage, including an unprecedented amount of distributed and customer-owned resources that its backers say might boost utility interest in storage as an alternative to centralized power plants.

The amount of energy storage resources unveiled by SCE is more than five times what the California Public Utilities Commission required for this solicitation. It's the first time SCE has chosen energy storage projects through competitive solicitation, the company said.

The winners -- Ice Energy Holdings Inc., Advanced Microgrid Solutions (AMS), Stem, NRG Energy Inc. and AES Corp. -- range from startups to large corporations and include several different technologies. AES will provide a more traditional 100 MW of utility-owned energy storage. The nation's largest grid-scale energy provider also just completed a 32 MW battery system for SCE two months ago.

Of particular interest is capacity offered by upstarts AMS and Stem, which aggregate customer-owned "behind-the-meter" resources mainly found in buildings and tout software and analytics rather than a specific technology.

Stem also won a $935,000 grant from the Department of Energy last month to develop an advanced software platform for energy storage management to improve the use of distributed storage in areas with abundant photovoltaic solar.

"This solicitation is the first time that such a wide range of new diverse resources were directly competing in the purchasing process," Colin Cushnie, SCE vice president for energy procurement and management, said in a statement. "No single energy source can give us everything we need all of the time, particularly with our emphasis to use environmentally clean resources. To provide for flexibility, we need to accommodate a mix of energy resources."

closing of the San Onofre nuclear power plant near San Diego and retiring natural gas plants that rely on ocean water cooling. Natural gas power plants will make up almost 80 percent of the substitute capacity, according to its **list** of the contract winners for its local capacity requirements request for offers.

SCE also contracted capacity from 135 MW of energy efficiency, 50 MW of distributed solar from SunPower Corp., and 75 MW from demand response -- a voluntary program to cut power use when demand is high in return for payment -- provided by NRG.

The contracts still require CPUC approval, the utility said.

If approved, the storage projects provide a good testing ground for other utilities considering energy storage resources, including California's two other investor-owned utilities that must meet the state mandate to acquire 1.3 gigawatts of energy storage for the grid by 2022.

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From: Koss, Kenneth L. <kenneth.koss@cpuc.ca.gov>
Sent: Wednesday, November 19, 2014 12:43 PM
To: Picker, Michael
Cc: Hammond, Christine J.; Chaset, Nicolas L.; Podolinsky, Elizabeth
Subject: FW: Quotes for Thursday?

Let us know if you need anything on this.

From: Prosper, Terrie D.
Sent: Wednesday, November 19, 2014 12:24 PM
To: Picker, Michael; Koss, Kenneth L.
Subject: Quotes for Thursday?

Hello,

If you would like quotes in any of the following press releases I am preparing for tomorrow in the event that the items are approved, please let me know by 9 a.m. on Thursday.

* 34: SONGS proposed settlement
* 36/36a: Order to Show Cause re: PG&E
* 38/38a: TNCs
* 51: SED OII

Thanks!

Terrie

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Message

From: Koss, Kenneth L. [kenneth.koss@cpuc.ca.gov]
Sent: 11/19/2014 2:37:27 PM
To: Picker, Michael [Michael.Picker@cpuc.ca.gov]
CC: Hammond, Christine J. [christine.hammond@cpuc.ca.gov]; Podolinsky, Elizabeth [elizabeth.podolinsky@cpuc.ca.gov]; Chaset, Nicolas L. [nicolas.chaset@cpuc.ca.gov]
Subject: Tomorrow's Agenda - Revised Items

We just got latest revisions on the following three PDs for tomorrow's agenda.
Copy of each for Michael on his table. Others in the "agenda" inbox on Josie's cube counter.

- San Onofre settlement – I.12-10-013 et al.
- TNCs – R.12-12-011
- LTTP – R.12-03-014 – Denies petition for modification

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From: Reardon, Neal <neal.reardon@cpuc.ca.gov>
Sent: Thursday, November 20, 2014 5:38 PM
To: Randolph, Edward F.; Walker, Cynthia; Picker, Michael
Cc: Strauss, Robert L.; Sterkel, Merideth
"Molly"; Chaset, Nicolas L.
Subject: CAISO Stochastic study shows dramatically increased need for resources

All,

FYI – Today we expect to receive testimony from the CAISO and SCE on the results of their respective stochastic (or "probabilistic") models. The intent of these models is to show what (if any) amount of flexible generation resources will be needed in 2024 to maintain system reliability given an increasingly variable supply and demand. Both the CAISO and SCE submitted modeling results earlier this year, but today's testimony is the first time they're both using a probabilistic model to evaluate needs in the LTPP trajectory scenario. Previous LTPPs have used a deterministic worst-case-scenario to plan around.

CAISO's modelers shared results with ED staff on Monday - but their management didn't offer and policy recommendations at that time. The results were surprisingly different from the CAISO's previous deterministic studies, and showed that:

- 8,271 MWs of flexible resources are needed to meet the "1-day-in-10 years" standard (compared with 1,489 MW need found in deterministic study)
  - However, the way CAISO calculates this reliability level is questioned by technical parties
- Maximum MW shortfall was 10 times higher
- GWh shortfall was 15 times higher
  - Both suspicious, as you'd expect the deterministic result to be at the high end of the probabilistic results

We don't have any preliminary results from SCE, but their previous probabilistic study of a high-load growth scenario showed 6200 MWs of need.

These results do not include 2315 MW in authorizations made after SONGS went down. Modelers haven't incorporated those because they resources aren't yet known.

No action item at this point. We will continue to provide updates as we analyze the testimony and process feedback from stakeholders.

-Neal

Neal Reardon, Senior Analyst
Generation and Transmission Planning Section
Energy Division
California Public Utilities Commission