Gayatri Schilberg
Economist/Consumer Advocate/Utility Slayer
Selected Documents and Decisions

Prepared testimony of
Gayatri Schilberg

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prepared for
Gayatri Schilberg

March 4, 2015

Executive Summary

Gayatri Schilberg had a unique career of service to consumers, to the environment and to the public interest as a whole over a 27 year period.

She came to JBS Energy in 1987. Her first assignments were related to utility resource planning, avoided costs of Hawaiian Island utilities, and electric demand forecasting. She developed considerable expertise on the valuation of environmental externalities, testifying at the California Energy Commission in several electricity reports and before the Ontario Energy Board.

She was heavily involved, along with virtually all of JBS, in the most massive project JBS ever did in its 30-year history – the review of Ontario Hydro's Demand/Supply plan for the Independent Power Producers' Society of Ontario. She also was a member of teams preparing two other major JBS reports with far-reaching consequences – the economic analysis supporting the South Coast Air Quality Management District's Rule 1135 on powerplant emissions of nitrogen oxides, and the *Photovoltaic Regulatory and Policy Issues* report prepared in 1995-96 for the National Association of State Utility Consumer Advocates.

Her consumer advocacy work began with the Pacific Bell Late Payment Charge case for TURN in 1992, where PacBell did not open mail, charged erroneous late charges, and disconnected customers who had actually paid their bills. She developed better estimates than Pacific Bell of the amount of erroneous charges and wound up being one of the few people who ever caused a utility to bring in a new expert witness to rebut not only Gayatri's work but the entire direct case filed by the utility's original expert.

From this start, she developed expertise in a number of critically important areas of utility operation in the areas of distribution, customer service and information technology.

She was involved in a number of projects related to the measurement and analysis of customer service. She designed customer service programs and evaluated problems related to several California utilities as well as Texas, Maryland, Nevada, and Alberta. She adopted the position (originated in the UK) that paying individual customers was the right remedy for many customer service errors. She also consistently claimed that objective indicators of performance were better than subjective surveys. Her views in this area were borne out when Southern California Edison committed fraud with consumer surveys to increase its shareholder rewards under Performance-Based Ratemaking, and Gayatri was there to figure out the extent of the fraud.

She also became expert in the arcane issues involved with the measurement of utility reliability as used in shareholder incentive programs and as justification of capital projects.

She also worked on customer service issues for one of JBS' rare utility clients, preparing a study for Scottish Power compiling service quality practices across the U.S. in support of that company's proposal for service guarantees offered to regulators as part of its acquisition of Pacificorp.

She also was involved in Information Technology projects including a detailed review of the PG&E Customer Information System (rebuilt three times from 1990-2003 – just like Diablo Canyon). She developed the analytical concept of the "IT treadmill" where utilities would incur ever-increasing expenses for short-lived computer systems if they did not engage in prioritization, cost discipline, and buying more off-the-shelf products.

She became an expert in analyzing utility tree trimming practices, testifying in a number of rate cases and in the 1998 trial leading to the conviction of PG&E in Nevada County on charges including criminal negligence for a decade of inadequate tree trimming spending.

She also was analyzed utility storm and emergency response and served on a working group at the PUC to develop emergency standards and inspection and maintenance standards for California electric utilities. She also represented consumers on a committee of the California Independent System Operator on reliability issues.

Her testimony demonstrated that Southern California Edison's deferred pole inspections for more than a decade contributed to its need to replace large numbers of poles. While the remedy that she proposed, was not adopted, the Commission found Edison at fault for causing some of its pole replacements by not doing timely inspections.

Gayatri also testified on a number of other distribution operational issues including the development of holistic and comprehensive estimates of underground cable replacement needs, the assignment of greater amounts of pole replacement costs to communications companies, and means of better quantify the costs that utilities would actually require for pole replacement. Her last work before her retirement was a comprehensive analysis of Southern California Edison's multi-billion-dollar replacement program for overloaded and high-wind area poles.

Gayatri left consumers and others with the legacy of an amazing body of work as a consummate economist and systems analyst during her time with JBS.

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Year/ Client	Case or Decision	Page	Description
1993 TURN	CPUC Decisions D.93-05-062 and D.94-04-057	57	TURN filed complaint (3/1/1991) against Pacific Bell (telecommunications) before CPUC alleging Pacific unlawfully imposed late payment charges and disconnected customers between 1986 and 1991. TURN also alleged that Pacific's management was aware of the practice and consciously chose to continue it, ignoring the Company's tariffs, to the a) benefit of its shareholders and the b) detriment of its customers. TURN estimated the erroneous charges amounted to $33 million. TURN also sought a shareholder penalty of $50 million. Gayatri filed testimony that estimated the customer refund amount and providing evidence of management complicity. Pacific Bell admitted to some erroneous charges but claimed it took immediate action to remedy the situation when it first understood the situation. Pacific estimated its erroneous charges amounted to $3 million and it opposed any imposition of a penalty. The CPUC found Pacific guilty of all offenses and ordered Pacific to refund $34.32 million in late payment charges and imposed a $15 million penalty on the Company's shareholders.
1997 Nevada County District Attorney	Nevada County versus PG&E	89	Nevada County District Attorney's office filed criminal charges against PG&E for negligence and causing a devastating wildfire in Sierra's in 1994. Gayatri submitted evidence that PG&E had diverted about $77 million from customers between 1987 and 1994 that it told the CPUC was needed to protect the public from the threat of wildfires to its shareholders. Some of the most damaging evidence produced by Gayatri came from internal memorandum from PG&E's corporate headquarters praising field managers for cutting tree trimming costs.

Year/ Client	Case or Decision	Page	Description
1998 TURN/ ORA	CPUC Decision D.98-03-036	93	Electric Distribution Facility Standards. A. 94-12-005, PG&E GRC. Got the CPUC to adopt standards for utility responses to major storms and outages. Joint TURN/ORA testimony on Emergency Response Standards. Create emergency plan, train staff, coordinate with media and others, and develop mutual assistance agreements.
2002 Disability Rights Advocates	CPUC Decision D.02-04-026	111	Baseline OIR – Commission adopted a number of Gayatri's recommendations to improve outreach for medical baseline and simplify the application process.

Year/ Client	Case or Decision	Page	Description
2004 TURN	CPUC Decisions, D.04-05-055 and D.04-10-034	126	PG&E 2003 GRC Phase I—A. 02-11-017 In response to PG&E's Phase I GRC request for recovery of its storm related costs, Gayatri filed testimony opposing that cost increase providing testimony on PG&E's proposed reliability targets and subsequent incremental funding request. In D. 04-10-034, the Commission adopted nearly all of TURN's proposals storm response and other reliability issues. The CPUC made the following findings; • It agreed with TURN that PG&E's response was not reasonable regarding outage information on its system, • PG&E's prior value of service studies were outdated and any new studies on value of reliability should include a "willingness to pay" element, • Agreed with TURN that PG&E should amortize a number of its outage information investments as well as be denied funding for certain aspects of its outage IT projects, • Based on TURN's testimony it denied a PG&E/CUE request for $27 million in incremental funding based on TURN's analysis that PG&E should meet and exceed proposed reliability targets levels without any incremental funding. • Also agreed with a number of other policy recommendations concerning call center standards and ratemaking treatment for storm related and reliability investments.

Year/ Client	Case or Decision	Page	Description
2005 UCAN	CPUC Decision D.05-08-037	147	SDG&E Catastrophic Event Memo Account A. 04-06-035. During 1994 SDG&E applied to the CPUC to recover its costs for catastrophic wildfires that occurred in its service territory. SDG&E originally applied to recover $62.7 million from its distribution retail but reduced that figure by $21.9 million to reflect funds that it had already been authorized for this purpose and sought recovery of $40.8 million. On behalf of UCAN, Gayatri intervened with recommendations on ratemaking treatment as well as a number of policy recommendations. The proposed decision adopted most of UCAN's recommendations and found that SDG&E failed to exercise reasonable control over its service vendors and also failed to offset its incremental costs with an existing rate allowance for those pole inspection and replacement --costs. The proposed decision adopted UCAN's proposed disallowances for these items. The final decision did not adopt these recommendations but found that UCAN's contribution was substantial by insisting that the Commission review the reasonableness of UCAN's costs estimates to ensure a more detailed review of SDG&E's cost wildfire cost estimates.
2006 Alberta CCA and PICA	Alberta Energy and Utilities Board Decision 2006-104.	187	Testimony for the Consumer Group caused the Alberta Energy and Utilities Board to reject giving Enmax Energy an advance incentive payment for meeting service quality standards before those standards existed and were adopted by the Board. "The C[onsumer Group] also presented evidence suggesting that under EEC's proposal, there is a probability that the existing levels of service would be provided at a 30% increased cost, such that "customers would pay more and get nothing in return." [citing Page 15 of Schilberg Evidence.]
2006 TURN	CPUC Decisions D.06-05-016 and D.06-10-018	196	SCE 2006 GRC – Got SCE to lower request by $40.8 million due to stipulation on reducing Priority 5 maintenance costs.

Year/ Client	Case or Decision	Page	Description
2007 TURN	CPUC Decision 07-03-044 CPUC PG&E Advice Letter 2838-G/3059-E	211 224	Gayatri was responsible for a PG&E service guarantee to pay customers who were shut off in error, as proposed in PG&E's 2007 GRC. See attached PG&E Advice Letter Advice 2838-G/3059-E ("Quality Assurance Standard Ten for Erroneous Service Termination in Compliance with Decision 07-03-044"). Hayley Goodson remembers: "When TURN was negotiating this with PG&E, they referred to it as the Schilberg Service Guarantee, which is how I've always thought of it since then."
2007 TURN	CPUC Decision D.07-05-058	230	She saved the vast majority of PG&E's branch offices a few years back. PG&E proposed to close all 84 local offices in its 2007 GRC, and we settled for keeping 75 open They are still open and continue to be well-used by PG&E customers.
2007 TURN	CPUC Decision D.07-09-041	252	Improving Access to Medical Baseline – Filed on behalf of Disability rights Advocates – R.01-05-047
2008 TURN	CPUC Decision D.08-03-012	315	PG&E Backbilling Case from 2003 GRC. This decision found that TURN made a substantial contribution in an investigation of PG&E's having backbilled customers $35 mm over multi-year period.(D.07-09-041 adopted most of TURN's recommendations in this investigation..
2008 TURN	CPUC Decision D.08-07-046	336	Gayatri also helped defeat SoCalGas's proposal to close 7 of its 47 branch offices in the Sempra 2008 Cost of Service Proceeding -- and got the Commission to order the Sempra utilities to stop contracting with payday lenders as authorized utility payment locations. See D.08-07-046, issued in A.06-12-009 et al., pp. 20-21. Of course SoCalGas now has a pending request to close 6 of the 7 branch offices that TURN saved in 2008.Gayatri's work in that case -- A.13-09-010 – is pending, and we are hoping with confidence that this work will be successful as well.

Year/ Client	Case or Decision	Page	Description
2008 TURN	CPUC Decision D 08-09-038 in OII 06-06-014	353	In D. 09-07-022 CPUC found TURN contributed to D. 08-09-038—investigation into SCE's fraudulent survey of customer satisfaction indices to wrongly claim PBR rewards. SCE had to refund $48 mm in customer satisfaction incentives, $35 mm in safety incentives. Also refund $32.714 mm in fraudulent results sharing and ordered SCE to pay a $30 mm fine.
2009 TURN	CPUC Decision D09-07-019	373	Service Standards for wireless providers – provided analysis refuting telecom claims that customer complaints were not numerous to worry about. OTHER D.10-07-014 – found TURN contributed to Decision D.09-07-019.
2009 TURN	CPUC Decision D-09-03-025 SCE 2009 GRC – A. 07-11-011	412	Contributed to D. 09-03-025— SCE 2009 GRC Phase I – A. 07-11-011— In Edison's 2009 GRC Phase I, Gayatri intervened on behalf of TURN on customer service issues as well as tree trimming and pole inspections and pole attachment fees. • Agreed with TURN to implement a moratorium on use of pay day lenders as authorized payment agents agreeing with TURN that customers paying bills at Authorized Payment Agents (APA) are normally the most economically vulnerable and establishing APAs at payday lenders will establish them as targets of predatory lenders. • Maintained the existing policy of funding utility service guarantees to customers using shareholder funds, • Convinced the Commission that Edison's forecast of intrusive inspections of its wood distribution poles is excessive, • Agreed to implement changes to its tariff language concerning billing errors to ensure consistency with California's other investor owned utilities.

Year/ Client	Case or Decision	Page	Description
2013 TURN	CPUC Decision D. 13-08-002	415	SCE 2012 GRC –Gayatri submitted testimony on Edison's request to recover hundreds of millions of dollars in capitalized software design and development. The Commission largely agreed with Gayatri's testimony and ordered all future capitalized software requests be justified by more detailed and cost justified analysis. Specific projects that were disallowed based on Gayatri's findings included, • Interactive Voice Response (IVR) $8.2 million • Customer Relationship Management (CRM) $4.5 million • Remove all funding for HAN support • Removed $16.3 million in IT O&M associated with AMI from base rates • Made an across-the-board 10% reduction to all IT capitalized software
2014 TURN	Excerpt from Testimony filed in A. 13-11-003 (SCE 2014 PHASE 1)	452	The case is still pending. Her last major piece of work, examined Edison's multi-billion dollar program to relieve overloaded poles at electric ratepayer expense. The testimony recommended that telecommunications companies be given the choice to remove attachments that caused overloading or pay for remediation; proposed a one-time "catch-up" fee for poles with joint owners or attachments. She also proposed to disallow costs for a make-work program to replace perfectly good, although aged poles that had previously passed inspection. She also recommended both lower unit costs of replacing poles and a lower number of poles requiring replacement, as well as more payments by telecommunications companies for routine pole maintenance.

Qualifications of Gayatri M. Schilberg

Gayatri Schilberg is a Senior Economist and expert witness with over thirty years of experience in economic and statistical research and business applications. She has concentrated on utility issues for the last twenty four years.

Ms. Schilberg has three degrees in economics: a B.A. from Oberlin College (1968), an M.A. from the University of Wisconsin (1969), and an M.Phil. from Oxford University (1973).

In July, 1987, Ms. Schilberg joined JBS Energy as a Senior Economist, where she is an expert on quantification of energy savings to demand response programs, customer service for both energy and telecommunications utilities, expenditures on information technology (IT) systems, utility revenue requirements for tree trimming and distribution maintenance, economic analysis of the value of reliability for utility planning, and quantification and modeling of energy and environmental issues.

Ms. Schilberg has testified at the California Public Utilities Commission (CPUC) on many occasions on utility customer service and operational issues, quantification of demand response, IT spending and benefits, customer service and reliability issues in Performance-Based Ratemaking (PBR), emergency response and emergency standards; tree trimming, deferred pole maintenance and other distribution expenses; medical baseline; meter reading practices; and erroneous late payment charges.

She presented testimony before the Public Utilities Commission of Nevada on several occasions regarding PBR service quality mechanisms. Ms. Schilberg testified before the Alberta Energy and Utilities Board on service quality as well as customer harm from sale of the retail utility functions. She testified at the Nevada County (California) Municipal Court on PG&E's spending on tree trimming. She has also testified at the California Energy Commission (CEC) and the Ontario Energy Board on valuation of environmental externalities; and at the CEC on demand forecasts and in a siting case. She has also filed testimony at the Maryland PSC on service quality issues. Ms. Schilberg conducted a nationwide survey on utility customer service standards, and has served on a CPUC task force to create inspection, maintenance, and reliability standards for electric utilities. She has served as a member of a committee on transmission planning standards for the California Independent System Operator (ISO).

Relating to environmental issues, Ms. Schilberg estimated the energy impacts of the South Coast Air Quality Management District's 1994 Air Quality Management Plan and its Rule 1135 on powerplant emissions. She prepared a major report on valuation of environmental externalities for Environment Canada, and supervised the preparation of major reports for the Photovoltaic Education Program of the National Association of State Utility Consumer Advocates. In the area of quantitative analysis, she reviewed CEC demand forecasts in three Electricity Reports, and also modeled generation systems of three Hawaiian utilities.

Earlier Ms. Schilberg worked for the United Nations Conference on Trade and Development in Geneva, Switzerland.

P.O. Box 191134
Sacramento, CA 95819-1134
July 6, 1987

Mr. James E. Helmich
President
JBS Energy
311 D Street
West Sacramento, CA 95819

Dear Jim:

Thank you for your warm letter of July 1, 1987 and offer of employment. I am happy to accept your offer as described in that letter.

I am pleased to have found associates of a high caliber in a flexible working environment, and look forward to learning and developing in the field of energy economics. I feel that this position will challenge many of my skills -- analytical, computer, "detective", and I welcome this opportunity and its growth potential.

I am available for work in mid-July and will contact you regarding my starting date when my schedule becomes more firm. I am very happy to be joining the team at JBS energy and look forward to seeing you soon.

Sincerely,

Gayatri M. Schilberg

Gayatri M.Schilberg

February 29, 1988

Memo to: Everyone

From: Gayatri

Re: HP Printer Facilities

J B S E N E R G Y , I n c .

To access our new laser printer we have to do two things:

1) Physically move the printer cable. It's default position should **always** be the draft printer, so if you couple it to the laser, put it back afterwards. This can't be stressed enough, so form the habit of changing the plug back to the draft printer as you take your paper out of the laser. The printer cable plugs into the BACK LEFT of the laserjet II. If you have the cable plugged into the wrong machine you will get a mess and waste a lot of paper.
2) Use the appropriate software. For newword this means calling a different program. For supercalc this means using the required setup codes.

A word of caution:
It's easy to waste paper with laser printers. It is highly recommended that from now on we print only the first page of our print job, go to see that it's coming out right (on the correct printer, correct font, etc) and then print the rest.

An added feature:
We can now put stationery or special paper in the laser paper tray and print out directly on the special paper. Letterhead goes in top to the wall, face up.

A. WORD PROCESSING

1. Calling the program

There are two newword programs installed for the HP laserjet II. To print an 8.5 x 11 inch sheet in portrait mode (like normal letters), use NWHP. To print in landscape mode (sidewise) call NWHPLAN. To take full advantage of landscape mode (for example, in timelines) be sure to extend the right margin in your newword document. If there is enough demand I will also install a version for laser printed envelopes.

2. Features

We continue to have a great capability for sub- and superscripts, accessed with control P control V and control P control T respectively. So our values of R^2 look nice and we have equations like $BTU= a + b * KWH + c * KWH^2$. In addition, our equations like $STAUSE_t-STAUSE_{t-1}=a + b\ (DIESL_t-DIESL_{t-1})$ will look better.

To change line height in the middle of a document using the .lh command, be aware that the default is 6 lines per inch (called by ".lh8"). So if you want
to squeeze the lines together and make roughly 8 lines per inch, use a line height of 6. This will make the lines print tighter, as is happening now. I repeat, to make the illustration longer, to squeeze the lines together and make roughly 8 lines per inch, use a line height of 6. This will make the lines print tighter, as is happening now.

We now also have the possibility to use alternate characters, called by control P @, which acts as a toggle. So we can write letters to Québec and we can talk about 2½, ¿Porqué?, and sell contracts of ¥5 million. Use the control P @ and type the normal letter from the table which corresponds to the special letter you want, followed by the control P @.

Table of Special characters

```
 !"#$%&'()*+,-./0123456789:;<=>?
 ÀÂÈÊËÎÏ´`ˆ¨˜ÙÛ£¯Ýý°ÇçÑñ¡¿¤£¥§ƒ¢

@ABCDEFGHIJKLMNOPQRSTUVWXYZ[\]^_
âêôûáéóúàèòùäëöüÅîØÆåíøæÄìÖÜÉïßÔ

`abcdefghijklmnopqrstuvwxyz{|}~
ÁÃãĐðÍÌÓÒÕõŠšÚŸÿÞþ·µ¶¾–¼½ªº«■»±
```

B. CAPABILITIES FROM SUPER CALC 2

1. General

Changes to the laser print via Supercalc will be made through the setup strings. These strings will turn on a function. The best way to turn off the function is on the printer's control panel--push the on-line button to toggle the printer off line, then hold down the continue-reset button until "07-reset" appears in the control panel. Newword will override any features turned on via supercalc.

2. Print style

To change from normal courier to compressed print, insert the following in the setup string:

escape (s16.66H

(be sure the last letter is a CAPITAL H, no space after the escape).

3. Landscape mode

To change to landscape (sidewise) printing insert the following in the setup string:

escape &l1O

(escape, followed by no space and the letters ampersand and small letter ℓ, followed by the number one and letter capital O.

4. Landscape compressed

To do both landscape and compressed, insert first the landscape code followed by the compressed code in the setup string. Be aware that since the pitch on the laserjet compressed print font that we have is 16.6, expect to get only 166 characters across a sidewise page, unlike 255 on the draft printer. To get more characters we have to investigate using legal paper.

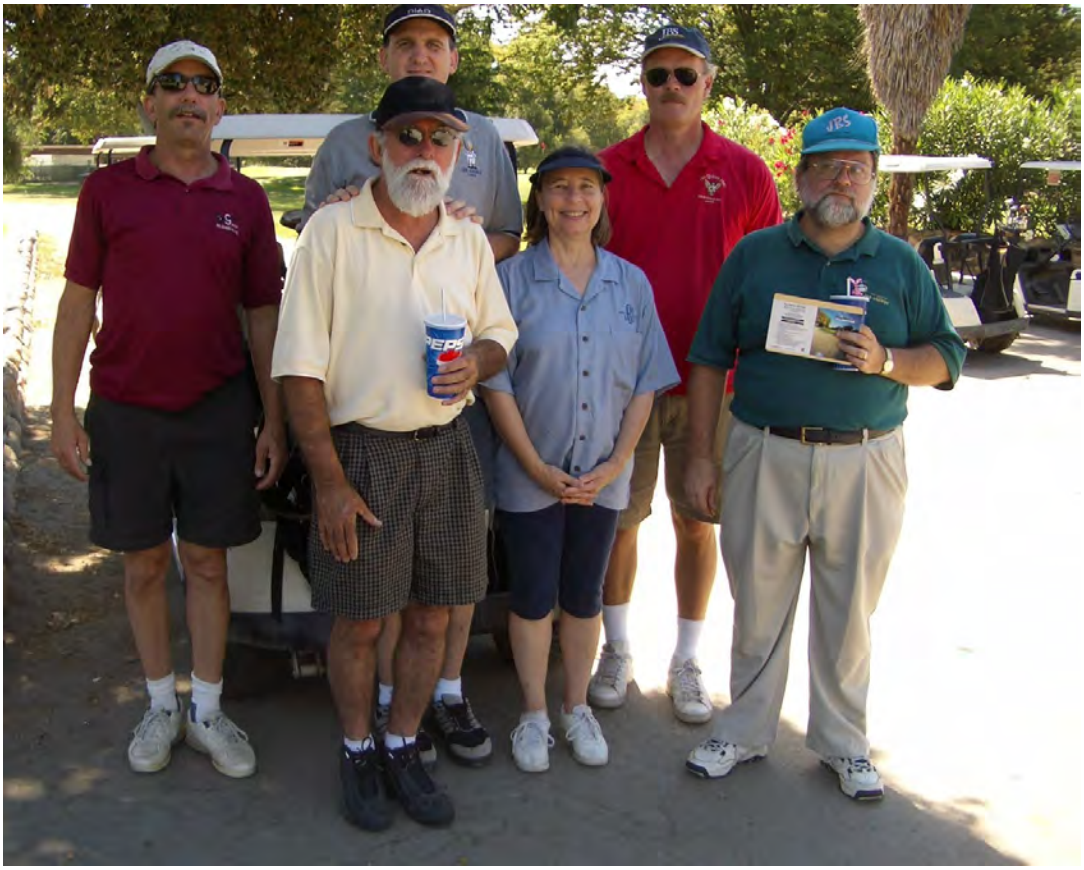
JBS Pictures

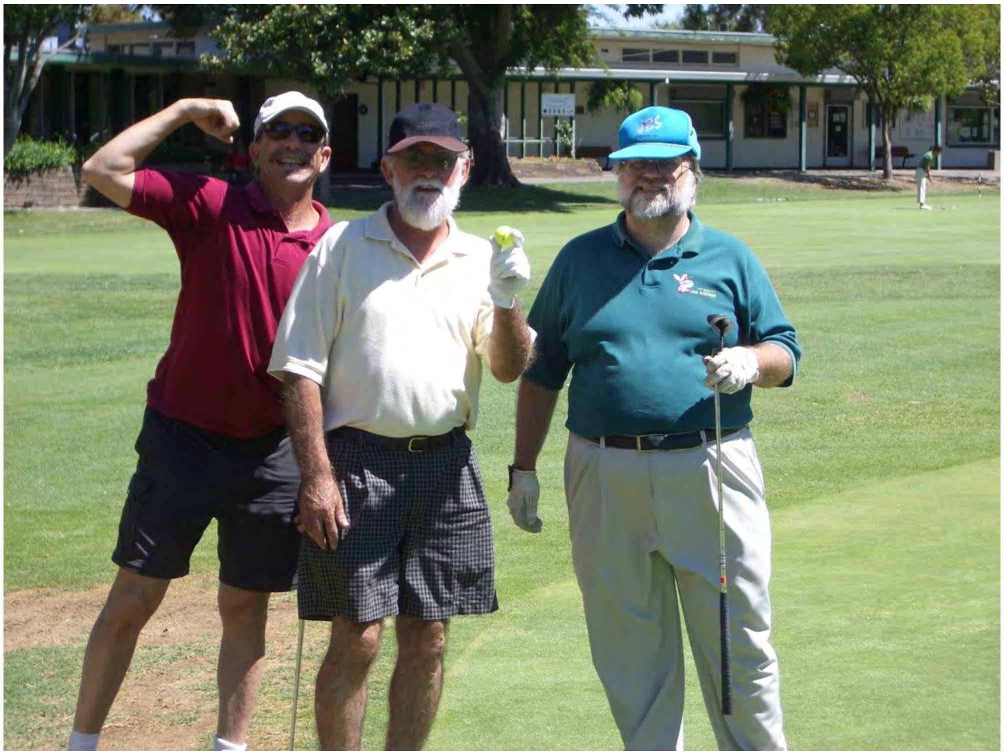
JBS Early Years

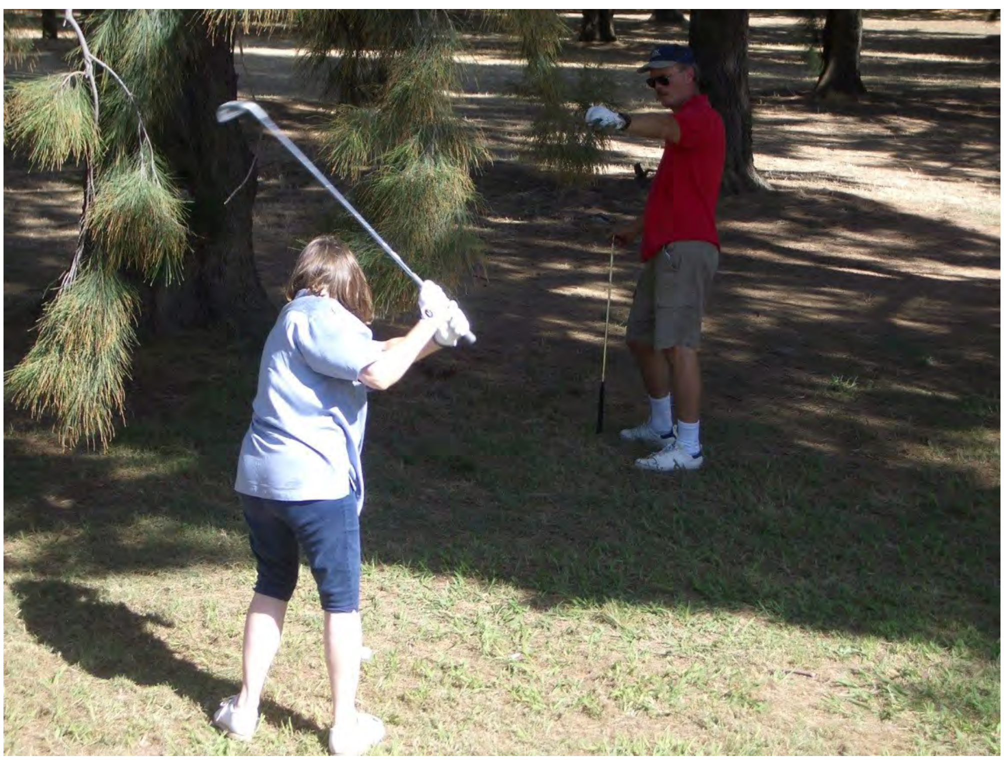
JBS Christmas 2000

JBS Christmas 2003

JBS 20th Anniversary Golf Game



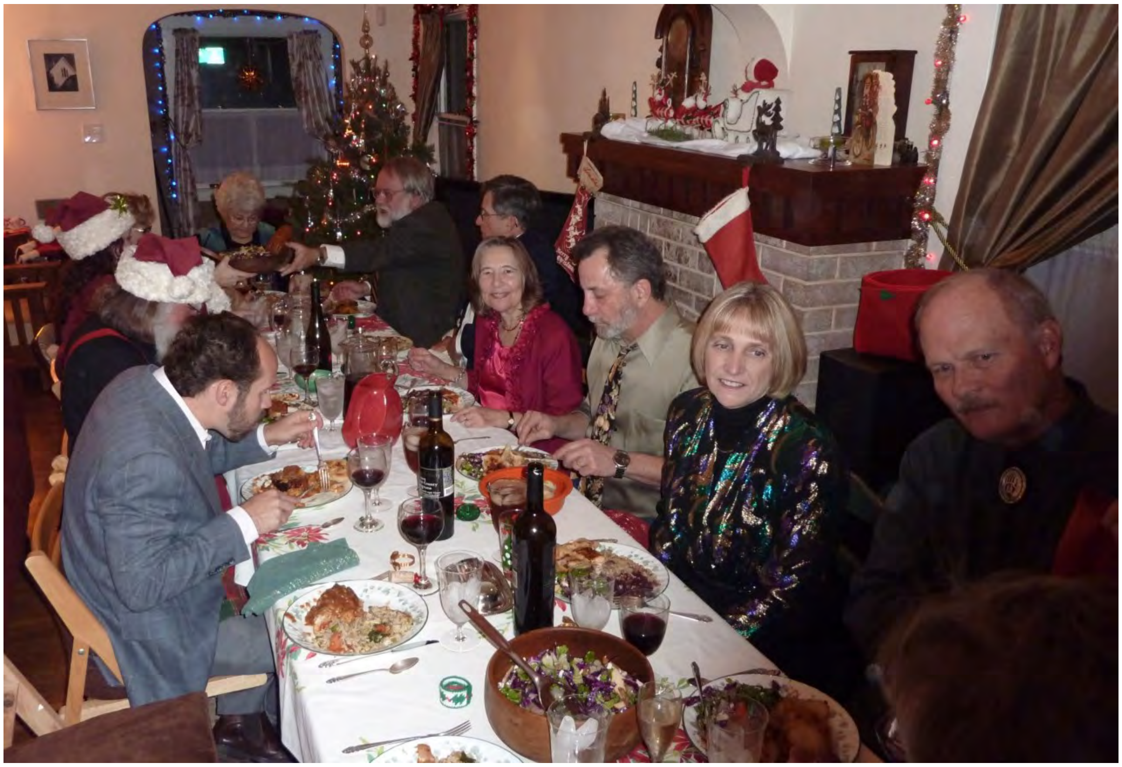




JBS Christmas 2006

JBS Christmas 2007

JBS Christmas 2011



Raclette Party at JBS 2013

RULE 1135. EMISSIONS OF OXIDES OF NITROGEN FROM ELECTRIC POWER GENERATING SYSTEMS

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

(Adopted August 4, 1989)(Amended December 21, 1990)(Amended July 19, 1991)

RULE 1135. EMISSIONS OF OXIDES OF NITROGEN FROM ELECTRIC POWER GENERATING SYSTEMS

[NOX LIMITS EXCERPTED]

(a) Applicability

This rule applies to electric power generating systems.

(b) Definitions

1. ADVANCED COMBUSTION RESOURCE means a combustion resource, within or outside the District, irrespective of ownership, capable of generating electricity using cogeneration; combined cycle gas turbines; intercooled, chemically recuperated, or other advanced gas turbines; and other advanced combustion processes.
2. ALTERNATIVE RESOURCE means a resource, within or outside the District, irrespective of ownership, capable of generating electricity in a non-conventional manner, including, but not limited to: solar; geothermal; wind; fuel cells; electricity conservation; and electricity demand-side management measures.
3. APPROVED ALTERNATIVE OR ADVANCED COMBUSTION RESOURCE means an alternative resource or advanced combustion resource which is approved by the Executive Officer. The Executive Officer shall disapprove an alternative resource or an advanced combustion resource unless and until it:

    (A) Displaces boiler capacity existing in the District on or after July 19, 1991; and

    (B) Emits NOx at no more than 0.10 pound per net megawatt-hour~~s~~ (MWH) on a daily average basis if the resource is located within the District, or no more than 0.05 pound per net MWH on a daily average basis if the resource is located outside the District; for cogeneration facilities, the daily NOx emission per MWH shall be calculated after deducting 0.013 pound of NOx for each million BTU of useful thermal energy produced which is not used for electric power generation; and

    (C) Commences operation on or after July 19, 1991; and

    (D) Is proven to the satisfaction of the Executive Officer that the net megawatt-hours obtained or conserved are real, quantifiable, and enforceable.

4. ALTERNATIVE RESOURCE OR ADVANCED COMBUSTION RESOURCE BREAKDOWN means an unscheduled condition during which no net electric power is obtained from an approved alternative or advanced combustion resource for 24 continuous hours or more.
5. BOILER means any combustion equipment in the District fired with liquid and/or gaseous fuel, which is primarily used to produce steam that is expanded in a turbine generator used for electric power generation. This includes only units existing on July 19, 1991, which are owned or operated by any one of the following: Southern California Edison, Los Angeles Department of Water and Power, City of Burbank, City of Glendale, and City of Pasadena, or any of their successors.
6. COGENERATION FACILITY means equipment used to produce electricity and other forms of useful thermal energy through the sequential use of energy, as specified in Public Resources Code Section 25134.
7. DAILY means a calendar day starting at 12 midnight and continuing through to the following 12 midnight hour.
8. DISPLACE means either of the following:

   (A) The concurrent and enforceable reduction of equivalent boiler capacity from one or more designated boilers in the District, such that the combined electric power obtained from approved alternative or advanced combustion resources and designated boilers does not exceed the maximum permitted capacity of the designated boilers, on an hourly average basis; or

   (B) The reduction of boiler capacity, equivalent to the maximum electric power obtained from the approved alternative or advanced combustion resource, from one or more boilers in the District for not less than six months as specified in the Permit to Operate. The owner or operator of the boilers may apply to the Executive Officer for restoration of the displaced capacity in the Permit to Operate, which shall be approved upon:

   > (i) Disapproval of the previously approved alternative or advanced combustion resource which was based on such displaced capacity; and
   >
   > (ii) Evidence of compliance with all provisions of this rule after the restoration of the displaced capacity.

   During an alternative or advanced combustion resource breakdown, the associated displaced boiler capacity may be utilized up to a maximum of 120 hours in any calendar month, provided the Executive Officer is notified prior to such utilization.

9. DISTRICT-WIDE DAILY LIMITS means the daily emissions limits applicable to any electric power generating system, consisting of an emissions cap and/or an emissions rate.

(A) EMISSIONS CAP is expressed in pounds of NOx and calculated as the total daily NOx emissions in pounds from all boilers, replacement units, and approved alternative or advanced combustion resources in the District.

(B) EMISSIONS RATE is expressed in pounds of NOx per Megawatt-Hour and calculated as the total daily NOx emissions in pounds from all boilers, replacement units, and approved alternative or advanced combustion resources in the District, divided by the total daily net electric power generated and/or obtained in Megawatt-Hours from all boilers and replacement units in the District and approved alternative or advanced combustion resources within or outside the District. For the purposes of this calculation, 70 percent, or higher if proven to the satisfaction of the Executive Officer, of the net Megawatt-Hours obtained from an approved alternative or advanced combustion resource outside the District shall be used. NOx emissions during start-ups and shutdowns, up to a maximum of 12 hours for each event, shall not be included in the determination of the emissions rate for an electric power generating system if five or fewer boilers are in operation during this period.

NOx emissions from approved cogeneration facilities shall be calculated after deducting 0.013 pound of NOx for each million BTU of useful thermal energy produced which is not used for electric power generation.

10. ELECTRIC POWER GENERATING SYSTEM means all boilers, replacement units and approved alternative or advanced combustion resources owned or operated by, and approved alternative or advanced combustion resources and replacement units under contract to sell power to, any one of the following: Southern California Edison, Los Angeles Department of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any of their successors.
11. FORCE MAJEURE NATURAL GAS CURTAILMENT means an interruption in natural gas service due to unforeseeable failure, malfunction, or natural disaster, not resulting from an intentional or negligent act or omission on the part of the owner or operator of a boiler or a replacement unit, or a supply restriction resulting from a California Public Utilities Commission priority allocation system, such that the daily fuel needs of a boiler or a replacement unit cannot be met with the natural gas available.
12. NOx EMISSIONS means the sum of nitric oxides and nitrogen dioxides emitted, collectively expressed as nitrogen dioxide emissions.
13. REPLACEMENT UNIT for the purpose of this rule means equipment within an electric power generating system, irrespective of ownership, which permanently replaces boiler capacity existing on July 19, 1991 in the same system in the District, and meets the requirements of Best Available Control Technology (BACT), as determined by the Executive Officer. If the replacement unit's electric power output in net megawatts exceeds the permitted net megawatt capacity of the boiler(s) replaced, only the electric power generation and NOx emissions prorated to the permitted net megawatt capacity of the boiler(s) replaced shall be subject to the provisions of this rule.

14. START-UP OR SHUTDOWN is any one of the following events:

    (A) START-UP is the time period during which a boiler is heated to its normal operating temperature range from a cold or ambient temperature, or from a hot standby condition where no net electric power is produced for at least 8 hours.

    (B) SHUTDOWN is the time period during which a boiler is allowed to cool from its normal operating temperature range to a cold or ambient temperature, or to a hot standby condition where no net electric power is produced for at least 8 hours.

15. USEFUL THERMAL ENERGY means thermal energy used in any industrial or commercial process, or used in any heating or cooling application. This shall not include the thermal energy of any condensate returned from the process or application to the cogeneration facility, or any thermal energy used to produce electric power.

(c) Emissions Limitations

1. Southern California Edison, or its successor, shall not operate its electric power generating system unless the following District-wide daily limits on emissions rate and emissions cap are met during the applicable time period:

I. District-Wide Daily Limits

Lb-NOx Lb NOx/Net Megawatt (MW) Hr C Per Day --- Beginning December 31, 1989 1.10 Beginning December 31, 1990 1.01 Beginning December 31, 1991 0.91 Beginning December 31, 1992 0.82 Beginning December 31, 1993 0.72 Beginning December 31, 1994 0.63 Beginning December 31, 1995 0.53 Beginning December 31, 1996 0.44 Beginning December 31, 1997 0.34 Beginning December 31, 1998 0.25 Beginning December 31, 1999 0.15 13,400

1. Los Angeles Department of Water and Power, or its successor, shall not operate its electric power generating system unless the following District-wide daily limits on emissions rate and emissions cap are met during the applicable time period:

II. District-Wide Daily Limits

Lb-NOx Lb NOx/Net Megawatt (MW) Hr Per Day --- Beginning December 31, 1989 1.60 Beginning December 31, 1990 1.41 Beginning December 31, 1991 1.21 Beginning December 31, 1992 1.02 Beginning

December 31, 1993 0.82 Beginning December 31, 1994 0.73 Beginning December 31, 1995 0.63 Beginning December 31, 1996 0.54 Beginning December 31, 1997 0.43 Beginning December 31, 1998 0.29 Beginning December 31, 1999 0.15 5,400 Beginning December 31, 2004 0.15 6,400 Beginning December 31, 2009 0.15 7,400

1. The City of Burbank, the City of Glendale, and the City of Pasadena, or any of their successors, shall not operate their electric power generating system unless at least one of the following District-wide daily limits on emissions rate or emissions cap is met during the applicable time period:

   (A) For the City of Burbank:

III. District-Wide Daily Limits

Lb NOx/Net Date Megawatt (MW) Hr Lb NOx Per Day -- Beginning December 31, 1989 2.47 3,870 Beginning December 31, 1993 1.73 2,763 Beginning December 31, 1996 0.99 1,657 Beginning December 31, 1999 0.20 580 (B) For the City of Glendale:

IV. District-Wide Daily Limits

Lb NOx/Net Date Megawatt (MW) Hr Lb NOx Per Day -- Beginning December 31, 1989 2.52 2,940 Beginning December 31, 1993 1.76 2,050 Beginning December 31, 1996 1.00 1,170 Beginning December 31, 1999 0.20 390 (C) For the City of Pasadena:

V. District-Wide Daily Limits

Lb NOx/Net Megawatt (MW) Hr Lb NOx Per Day -- Beginning December 31, 1989 3.05 5,230 Beginning December 31, 1993 2.12 3,680 Beginning December 31, 1996 1.18 2,130 Beginning December 31, 1999 0.20 900

1. Electric power generating systems shall not emit NOx from all boilers, replacement units and approved alternative resources or advanced combustion resources in the District, for any calendar year beginning with 2000, in excess of the following limits:

   (A) 1,640 tons per year for Southern California Edison Co.;

(B) 960 tons per year for Los Angeles Department of Water and Power;

(C) 56 tons per year for the City of Burbank;

(D) 35 tons per year for the City of Glendale; if Grayson combined cycle gas turbine Unit 8BC cannot produce electricity because of a breakdown for 30 continuous days or more, the annual NOx emissions limit shall be increased by 65 pounds per day, up to a maximum of 41 tons per year.

(E) 80 tons per year for the City of Pasadena.

2. A violation of any requirement specified in paragraphs (c)(1), or (c)(2), or (c)(3), or (c)(4) shall constitute a violation of this rule for every permitted unit operating during the exceedance period in the applicable electric power generating system. This provision shall not be applicable to approved alternative or advanced combustion resources, and compliance shall be determined assuming that NOx emissions from approved alternative or advanced combustion resources occur at actual or permitted levels, whichever is lower.
3. All retrofit emission control devices required to meet the provisions of this rule for the year 2000 shall be installed and be operative on each boiler by December 31, 1997, except for the three cities of Glendale, Pasadena and Burbank for whom the deadline shall be December 31, 1999. All replacement units and approved alternative or advanced combustion resources required by the approved compliance plan for all the electric power generating systems shall be installed and be operative by December 31, 1999.
4. The owner or operator of each boiler and approved alternative or advanced combustion resource in the District shall submit an application for change of permit conditions to include NOx emission limits for each boiler and approved alternative or advanced combustion resource, as specified in the compliance plan requirements in subparagraph (d)(1)(C). Such applications shall be submitted no later than January 1, 1992, to the Executive Officer for approval.
5. A violation of any unit-specific NOx emissions limits established in a District Permit to Operate or approved compliance plan shall constitute a violation of this rule for that unit of the electric power generating system.

(d) Compliance Plans

1. Compliance Plan (Plan) approval and disapproval:

(A) Each owner or operator of a boiler shall submit a Plan by January 1, 1992 to the Executive Officer for approval. The Plan shall propose actions and alternatives which will be taken to meet or exceed the requirements of this rule.

(B) The Executive Officer shall seek input from the Air Resources Board (ARB), the California Energy Commission (CEC), and the California Public Utilities

Commission (CPUC) prior to approval of the Plan. All written comments received from the ARB, the CEC, and the CPUC for a CPUC-regulated utility, within 30 days of the receipt of the Plan, shall be considered by the Executive Officer for Plan approval.

(C) The Executive Officer shall disapprove the Plan unless the applicant proves to the satisfaction of the Executive Officer that the implementation of the Plan will result in timely compliance with all provisions of this rule. The approved Plan shall specify a NOx emission limit for each unit of the electric power generating system in Lb NOx per net Megawatt Hour on an hourly average basis; such emission limit shall not be applicable when the unit is not producing any net electric power, or during a start-up, a shutdown, or 12 hours for each start-up or shutdown, whichever is less.

(D) On and after July 1, 1992, failure to have an approved Plan or failure to implement the provisions of an approved Plan shall constitute a violation of this rule.

2. The Plan shall contain, at a minimum:

(A) A list of all boilers subject to this rule with the maximum rated net and gross generating capacity for each unit.

(B) A schedule of equipment to be controlled, displaced, or replaced, indicating the type of control to be applied to each existing boiler and the emissions reductions for each compliance increment, and identifying each unit to be displaced with an alternative or advanced combustion resource.

(C) Detailed schedules for submittal of permit applications, construction activities, and planned operation phases.

(D) A detailed list of all assumptions and calculations used to determine compliance with the District-wide daily limits.

(E) A list of the control devices and methods which are being proposed for each boiler specified in subparagraph (d)(2)(A), along with the percent NOx reduction efficiency assumed for each.

(F) Historical power generating data for each boiler and future resource plans used to support power generation mix assumptions.

(G) For each year, beginning with 1992, a graph of the NOx emission in Lb NOx/hour versus net Megawatts generated on an hourly average basis for the full load range of each unit of the electric power generating system burning natural gas that will result in compliance with the District-wide daily limits as specified in subsection (c), Emissions Limitations, for the following cases:

(i) Under a projected peak generation day for each future year of compliance, based on District guidelines, and

(ii) Individually for each unit, under maximum power generation for that unit on a projected peak generation day for each future year of compliance.

(H) Identification of conditions that may require an exemption under subsection (h) and the actions taken or to be taken to minimize or eliminate such conditions.

3. The Plan shall also include proposed increments of progress for the following:

   (A) Southern California Edison shall install and operate by December 31, 1993 a Selective Catalytic Reduction unit (SCR) on an existing 480 MW steam boiler such that NOx emissions from the facility do not exceed 0.25 pound of NOx per net MWH; and

   (B) Los Angeles Department of Water and Power shall replace at least 240 megawatts of existing steam boiler capacity by
   December 31, 1993 such that NOx emissions from the replacement unit do not exceed applicable Best Available Control Technology standards, as determined by the Executive Officer.

4. Not earlier than July 1 of any year following 1992, amendments to a previously approved Plan may be proposed to the Executive Officer as necessary to reflect energy regulatory agency resource or municipal authority planning determinations, adjustments to unit specific emissions limits required in subparagraph (d)(1)(C) in view of emissions control performance test data, and advancements in emissions control technology. The Executive Officer shall disapprove such amendments unless the applicant proves to the satisfaction of the Executive Officer that the implementation of the amended Plan will result in timely compliance with all provisions of this rule.
5. All approved Plans and approved amendments to Plans shall be submitted by the District to the Air Resources Board and the Environmental Protection Agency as source-specific revisions to the State Implementation Plan.

(e) Measurements

1. The owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall install, operate, and maintain in calibration a~~n~~ continuous emission monitoring system (CEMS) and a Remote Terminal Unit (RTU) to demonstrate compliance with the provisions of this rule.
2. Each CEMS shall meet all applicable federal, state and District requirements for certification, calibration, performance, measurement, maintenance, notification, recordkeeping and reporting, including, but not limited to, the requirements set

forth in the District's "CEMS Requirements Document for Utility Boilers," dated July 19, 1991. Prior to the installation of a CEMS, the owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall submit a revised detailed CEM Plan by October 19, 1991 for the approval of the Executive Officer. The CEM Plan shall contain all information required in the District's "CEMS Requirements Document for Utility Boilers," dated July 19, 1991.

3. Each RTU shall meet specifications set forth by the Executive Officer to ensure that emissions and other data necessary to determine compliance are reliably and accurately telecommunicated from each unit to the District in a format compatible with District equipment. Each RTU shall be installed with the prior approval of the Executive Officer by January 1, 1993.
4. Starting December 21, 1990 until January 1, 1993, the owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall submit a monthly compliance report to the Executive Officer, and shall make all data available to the District staff on a daily basis according to the interim reporting requirements specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991.
5. The owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall install testing facilities as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991, by January 1, 1993.
6. The owner or operator of each boiler, replacement unit and approved alternative or advanced combustion resource in the District shall install, maintain and operate a backup data gathering and storage system after each associated RTU is installed, but not later than January 1, 1993, as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991.
7. CEMS data shall be gathered and recorded at least once per minute at each boiler, replacement unit and approved alternative or advanced combustion resource in the District, and valid data, as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991, shall be obtained for at least 90 percent of the data points in any calendar day.
8. If valid data is not obtained by a CEMS for any boiler, replacement unit or approved alternative or advanced combustion resource in the District, the following alternative means of NOx emissions data generation may be used for not more than 72 hours in any one calendar month:

   (A) Reference test methods as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991; or

   (B) Load curves provided approval is obtained as specified in the "CEMS Requirements Document for Utility Boilers," dated July 19, 1991. New load curves shall be submitted for the approval of the Executive Officer if the basic equipment is modified.

(f) Use of Liquid Petroleum Fuel

1. The District-wide daily limits on emissions rate and emissions cap specified in paragraphs (c)(1), (c)(2), and (c)(3) shall not apply to an electric power generating system on days of force majeure natural gas curtailment when the use of liquid petroleum fuel is required, provided that:

   (A) Within 15 days of each occurrence, the owner or operator of each boiler submits an affidavit signed by a corporate officer affirming that liquid petroleum fuel was burned due to force majeure natural gas curtailment; and

   (B) Each boiler, when it burns natural gas exclusively, meets the applicable unit-specific NOx emission limit specified in subparagraph (d)(1)(C); and

   (C) Each boiler, when it burns liquid petroleum fuel exclusively, emits oxides of nitrogen at no more than 2 times the applicable unit-specific NOx emission limit specified in subparagraph (d)(1)(C); and

   (D) Each boiler, when it burns a combination of liquid petroleum fuel and natural gas, emits oxides of nitrogen at no more than the prorated limit for that unit, obtained from the requirements specified in subparagraphs (f)(1)(B) and (f)(1)(C), and weighted by the flow rate and gross heating value of natural gas and liquid petroleum fuel, respectively. The calculation procedure in the "CEMS Requirement Document for Utility Boilers", dated July 19, 1991 shall be followed.

2. A boiler may burn liquid petroleum fuel for up to 24 hours in any calendar year for fuel readiness testing provided that the emission limitation specified in subparagraph (f)(1)(C) is met. The unit specific NOx emission limit specified in subparagraph (d)(1)(C) shall not apply during this period.

(g) Municipal Bubble Options

1. Any electric power generating system may form a municipal bubble by linking with one or more electric power generating system(s), for the purposes of this rule, provided all of the following conditions are met:

   (A) The municipal bubble does not include Southern California Edison; and

   (B) The municipal bubble is formed for at least one year, or more; and

   (C) An application for approval of the municipal bubble is submitted jointly by all affected municipal utilities to the Executive Officer, at least six months in advance; and

   (D) Written approval of the application for the municipal bubble is obtained from the Executive Officer prior to utilization of any provision contained in subsection (g), Municipal Bubble Options.

2. The application for a municipal bubble required in subparagraph (g)(1)(C) shall include, without being limited to:

   (A) Proposed amendments to the compliance plans of all affected municipal utilities, as required to meet or exceed the municipal bubble emissions limitations specified in paragraph (g)(3); and

   (B) Applications for change of permit conditions to adjust NOx emissions limits for each boiler, replacement unit and approved alternative or advanced combustion resource in the District, as required by the proposed amendments to the compliance plans; and

   (C) Any other information required by the Executive Officer to evaluate compliance with the provisions of this rule.

   The Executive Officer shall not approve the application for a municipal bubble unless it is demonstrated to the satisfaction of the Executive Officer that such action(s) will result in compliance with the municipal bubble emissions limitations specified in paragraph (g)(3) in an enforceable manner.

3. Municipal bubble emissions limitations shall be derived from the District-wide daily limits on emissions rate and emissions cap specified in paragraphs (c)(2) and (c)(3), for each municipal utility, as follows:

   (A) The District-wide daily limits on emissions rate in pounds of NOx per net megawatt-hours shall be the sum of the emissions rates of each participating utility, weighted by the maximum permitted capacity of each utility as a fraction of the total permitted capacity in the municipal bubble, for the applicable time period; and

   (B) The District-wide daily limits on emissions cap in pounds of NOx per day shall be the sum of the emissions cap of all participating utilities, for the applicable time period, and beginning December 31, 1999, if Los Angeles Department of Water and Power is included in the municipal bubble; and

4. An electric power generating system subject to a municipal bubble approved by the Executive Officer shall be exempt from the utility-specific requirements of paragraphs (c)(2) and (c)(3); and be subject to the municipal bubble emissions limitations specified in paragraph (g)(3) for the applicable time period.
5. A violation of any municipal bubble emissions limitations required in paragraph (g)(4) shall constitute a violation for each permitted boiler and replacement unit, operating during the exceedance period, in the municipal bubble. This provision shall not apply to approved alternative or advanced combustion resources.

(h) Exemptions

1. Notwithstanding the provisions of paragraphs (c)(1) or (c)(2), Southern California Edison or Los Angeles Department of Water and Power may operate its electric power generating system if both the following District-wide daily limits on emissions rate and emissions cap are met:

VI. District-Wide Daily Limits

Lb NOx/Net Megawatt (MW) Hr Lb NOx Per Day -- ----------------------------- Southern California Edison 0.25 5,360 Los Angeles Department of Water and Power 0.25 2,960

1. Notwithstanding the provisions of paragraphs (c)(1), (c)(2), or (c)(3), an electric power generating system may be operated for no more than 10 calendar days in any calendar year if all the following conditions are met:

   (A) Both the following District-wide daily limits on emissions rate and emissions cap are met:

VII. District-Wide Daily Limits

Lb NOx/Net Megawatt (MW) Hr Lb NOx Per Day -- ------------------------------- Southern California Edison 0.25 20,100 Los Angeles Department of Water Power and 0.25 11,100 Burbank 0.25 870 Glendale 0.25 580 Pasadena 0.25 1,350; and

(B) The electric generating system owner/operator has taken all possible steps to comply with paragraphs (c)(1), (c)(2) and (c)(3), including the interruption of non-firm load.

(C) The exemption is not required as a result of operator error, neglect, or improper operating or maintenance procedures;

(D) Steps are immediately taken to correct the condition;

(E) The electric power generating system owner/operator reports to the District the need for the exemption within one hour of the occurrence or within one hour of the time said operator knew or reasonably should have known of the occurrence;

(F) No later than one week after each event the owner/operator submits a written report to the District including but not limited to:

(i) A statement that the situation has been corrected, together with the date of correction and proof of compliance;

(ii) A specific statement of the reason(s) or cause(s) for the exemption sufficient to enable the Executive Officer to determine whether the occurrence was in accordance with the criteria set forth in subparagraphs (h)(2)(B) and (h)(2)(C) of this rule;

(iii) A description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future.

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ANALYSIS OF COST-EFFECTIVE NOx CONTROL SCENARIOS ON FIVE SOUTHERN CALIFORNIA UTILITIES: ANNUAL AND PEAK DAY GENERATION

Volume I

Prepared for the
South Coast Air Quality Management District

March 25, 1991

ACKNOWLEDGMENT

This report was prepared by JBS Energy, Inc. for the South Coast Air Quality Management District.

William B. Marcus, Principal Economist, was the technical director of the project. He was responsible for project oversight as well as for writing large portions of the final report. He also prepared supply data sets and ran PROSYM for Burbank, Glendale, and Pasadena, and provided technical consultation in the preparation of data input into PROSYM for other utilities.

Gayatri Margaret Schilberg, Senior Economist, was the project manager. In addition to coordinating the work of the staff assigned to this project to assure completion of the many complex tasks associated with this project in an orderly fashion, she also prepared portions of the final report and was responsible for preparing supply data sets and running PROSYM and the Control Technology Cost-Effectiveness Model for Southern California Edison (SCE).

Gregory Ruszovan, Energy Analyst, prepared and ran the Los Angeles Department of Water and Power (LADWP) data sets, wrote the programs for the Control Technology Cost-Effectiveness Model, ran that model for LADWP, and designed the annual tables and graphs in Appendix M.

Kevin L. Hanson, Energy Analyst, wrote the programs for the Peak Day Emissions Model and ran it for all utilities, designed the peak day tables and graphs in Appendix M, conducted demand forecast research for Burbank, Glendale,and Pasadena, prepared hourly loads from demand forecasts for input into PROSYM for all of the utilities, and developed the nitrogen oxide emissions curves for SCE and LADWP.

Steven G. Helmich, Energy Analyst, disaggregated Southern California Edison Qualifying Facility projects into air basins and provided graphic and production support.

EXECUTIVE SUMMARY

I. Purpose of Study

This study responds to the request of the South Coast Air Quality Management District (the District) to analyze the Best Available Retrofit Control Technology (BARCT) for control of nitrogen oxides (NOx) in oil/gas steam powerplants belonging to five utilities in the South Coast Air Basin:

Southern California Edison Company (SCE or Edison)
Los Angeles Department of Water and Power (LADWP)
City of Burbank (Burbank)
City of Glendale (Glendale)
Pasadena Department of Water and Power (Pasadena).

II. BARCT and the Structure of the Rule

BARCT is a concept which includes both availability of technology and its cost-effectiveness in removing pollution in a retrofit application. The study therefore is based on the melding of the economics of retrofit technologies with utility system operations. The level of control for each utility system is based on removal of NOx up to a specific cost-effectiveness threshold which represents the maximum that would be required to pay to control any individual steam powerplant. The District asked us to analyze three such thresholds, $43,100, $21,100, and $16,400.

The rule based on BARCT would specify a level of control which is based on four parameters: (1) an annual cap on the total amount of pollutants for each utility specified in pounds per year; (2) an annual average rate for each utility, given as pounds of NOx per megawatt-hour (MWh); (3) a maximum daily cap in pounds of NOx per day; and (4) a maximum daily rate as pounds per MWh.

It is important to remember that while the basis of the rule is the application of a cost-effectiveness threshold to individual utility generating units, the specific rule contains only system-wide caps discussed above. The utility may choose to meet the rule's requirements in different ways than are shown in this study. This report only represents one way of attaining BARCT and the system-wide limits which result from that method.

III. THE ANALYTICAL FRAMEWORK AND ASSUMPTIONS

To make this analysis, two basic sets of data are required: (1) information on the amount that utility powerplants run and (2) data on how much NOx they would produce without controls and using controls found cost-effective under BARCT. To derive the former we used production simulation modeling based largely on load forecasts and resource characterizations from the California Energy Commission's 1990 Electricity Report (ER-90).[1] Data on quantities of NOx produced under the condition of no controls were generally taken from the utilities' Rule 1135 Compliance Plans, and supplemented with data from the individual utilities and the ER-90 datasets. The District supplied information on costs and NOx reduction of each type of control. A more detailed description of input assumptions appears in the general discussion in Chapter 1, and the discussion of each utility in Chapters 2-4.

We used the utility production simulation models to calculate annual and peak day generation and NOx production and a cost-effectiveness model to determine the level of controls for each powerplant that are BARCT. We considered the cost-effectiveness of the following NOx controls: urea injection (UI) at 30% NOx reduction, low NOx burners plus UI (LNB+UI) at 60% NOx reduction, and 90% selective catalytic reduction (SCR) plus UI for 93% NOx reduction. The production simulation model was then re-run with the new levels of controls (and corresponding changes in unit operation and maintenance costs) to estimate controlled NOx emissions under the three cost-effectiveness thresholds.

For the peak day analysis we assumed a stressed system defined as follows:

SCE -- peak day in August with SONGS 3 out
LADWP -- peak day in August with one unit of Intermountain (IGS) out
Burbank -- peak day (Oct 22) when the DC Intertie is on maintenance
Glendale -- peak day with one unit of IGS out
Pasadena -- peak day with one unit of IGS out.

IV. RESULTS

Detailed results for each utility are presented in chapters 2-4. We highlight the conclusions here.

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1 For the three cities, Burbank, Glendale and Pasadena, we relied on in-depth research with each city as to their resource characterizations. The ER-90 ELFIN datasets, upon which our general information was based, included the three cities together with LADWP, and we had to separate out each utility for this analysis.

A. Southern California Edison Company

1. Annual Generation

By the year 2000, total in-basin oil/gas generation rises from 12,952 GWh recorded in 1988 (including combined cycles and peakers) to 19,751 GWh, an increase of 52.5%. However, the composition of this oil/gas generation, under the CEC's ER-90 scenario, changes dramatically because of repowerings. By the year 2000, the repowerings of Alamitos 1-2 and Huntington Beach 3-4 provide 13,015 GWh, of which 4416 GWh relates to replacement megawatts and 8599 GWh to new megawatts. As a result, steam generation in the basin falls to 6521 GWh, 48% less than recorded 1988 in-basin steam generation of 12,547 GWh.

Between 2000 and 2009, load grows by 16,887 GWh. This load growth is met with a significant amount of repowering and new combined cycle generation under the CEC's ER-90 assumptions, as well as utility-owned geothermal. Total combined cycle generation rises by 11,345 GWh, and 8044 GWh of utility-owned geothermal is added. Other non-oil/gas options rise by 541 GWh, with conservation providing over half of this amount. As this increase from new generation sources is greater than load growth, conventional steam generation is reduced by 1492 GWh in-basin (to 5029 GWh) and by 1550 GWh outside the basin.

Annual emissions and emissions rates are given in Tables E-1 to E-3 for the three control scenarios. At all cost-effectiveness levels, our results show an erosion in the effectiveness of controls due to increased in-basin generation and NOx emissions from 2000 to 2009. The erosion in the effectiveness of controls is most pronounced at low cost-effectiveness caps.

Table E-1
SCE Emissions At $43,100 Cost-Effectiveness Level

	(Thousands of Pounds)		(Pounds per MWh)	
Year	2000	2009	2000	2009
Steam Plants	546	413	0.08	0.08
Replacements	654	1027	0.15	0.15
Total 1135	1200	1440	0.11	0.12
Total In-Basin[2]	2474	2798	0.13	0.13

[2] Total in-basin includes new combined cycles as well as 1135 units.

Table E-2

SCE Emissions At $21,100 Cost-Effectiveness Level

	(Thousands of Pounds)		(Pounds per MWh)	
Year	2000	2009	2000	2009
Steam Plants	1474	1441	0.24	0.29
Replacements	654	1026	0.15	0.15
Total 1135	2128	2466	0.20	0.21
Total In-Basin	3401	3823	0.18	0.18

Table E-3

SCE Emissions At $16,400 Cost-Effectiveness Level

	(Thousands of Pounds)		(Pounds per MWh)	
Year	2000	2009	2000	2009
Steam Plants	2052	2739	0.32	0.35
Replacements	653	1026	0.15	0.15
Total 1135	2705	3765	0.25	0.23
Total In-Basin	3976	5121	0.21	0.20

2. Peak Day Rule Quantification

Adding 1.0 to 1.5 standard deviations to the mean yields the following results for the 1135 system (based on the year 2000 only).

Table E-4

Daily Cap and Daily Rate Calculations, SCE

	$43,100	$21,100	$16,400
Mean (pounds)	5862	12415	15738
Daily cap (pounds)	6772-7227	14139-15001	17808-18843
Daily rate (lb./MWh)	0.134-0.143	0.268-0.281	0.336-0.351

B. Los Angeles Department of Water and Power

1. Annual Generation

According to the CEC forecast LADWP's demand is rising more slowly than Edison's. Thus apart from 150 MW of geothermal at Coso, relatively little new net generation is warranted. Should more generation be added from out-of-basin resources, air quality would be improved relative to the modeled scenarios, but should gas-fired resources be added in-basin, increased emissions are likely.[3]

Between 2000 and 2009, load grows by 4553 GWh. Steam plants made up the bulk of the increased generation over this period, rising 125% (3679 GWh) to 6629 GWh.

3 Subsequent to our development of this analysis, we were informed by CEC that a second CEC resource plan exists which includes more resources for LADWP, although it is not the official ER-90 data set.

Tables E-5 to E-7 give LADWP annual results under the three control scenarios.

Table E-5

LADWP Annual Emissions At $43,100 Cost-Effectiveness Level

	(Thousands of Pounds)		(Pounds per MWh)	
	2000	2009	2000	2009
Steam Plants	334	354	0.11	0.05
Replacements	622	705	0.15	0.15
Total 1135	955	1059	0.13	0.09
Total In-Basin	955	1233	0.13	0.10

Table E-6

LADWP Annual Emissions At $21,100 Cost-Effectiveness Level

	(Thousands of Pounds)		(Pounds per MWh)	
	2000	2009	2000	2009
Steam Plants	552	354	0.19	0.05
Replacements	621	705	0.15	0.15
Total 1135	1173	1059	0.16	0.09
Total In-Basin	1173	1233	0.16	0.10

Table E-7

LADWP Annual Emissions At $16,400 Cost-Effectiveness Level

	(Thousands of Pounds)		(Pounds per MWh)	
	2000	2009	2000	2009
Steam Plants	1169	813	0.40	0.12
Replacements	621	705	0.15	0.15
Total 1135	1780	1517	0.25	0.13
Total In-Basin	1780	1691	0.25	0.14

Under the two most stringent control strategies, in-basin NOx emissions increase after the year 2000. The addition of controls to a number of units between 2000 and 2009. mitigates the 107% increase found in the uncontrolled scenario, but emissions still rise 31% in the $43,100 control scenario and 5% in the $21,100 control scenario. In the $16,400 control scenario, where emissions controls are much more stringent in 2009 than in 2000, emissions decreased 5% from 2000 to 2009.

It is likely that additional resources would need to be added to balance loads and resources by 2009 even under a CEC-based scenario. Addition of new net generation from in-basin combined cycles would be very likely to increase year 2009 emissions in the two highest cost control scenarios because (1) combined cycles have greater NOx emissions in pounds per MWh than SCR based controls on steam units (although less than LNB+UI) so that displacement of steam generation with SCR by in-basin combined cycles would raise in-basin emissions, and (2) combined cycle generation would reduce steam boiler capacity factors, possibly rendering controls on these units less cost-effective.

2. Peak Day Rule Quantification

Adding 1.0 to 1.5 standard deviations to the mean peak day NOx production and peak day daily rate yields the following results for the in-basin system (based on the 1135 system and the year 2000 only).

Table E-8

Daily Cap and Daily Rate Calculations LADWP

	$43,100	$21,100	$16,400
Mean (pounds)	4121	5525	11421
Daily cap (pounds)	4659-4928	6036-6292	12672-13297
Daily rate (lb./MWh)	0.140-0.147	0.184-0.191	0.375-0.386

C. General Interpretation for the Three Cities

The reliability of the load forecast used for this analysis is a major factor in the interpretation of our results for the three cities. To the extent the that CEC's annual forecast of peaks and energies is too low, which is the view of the Cities themselves, any action taken on the basis of these results must consider the consequence of higher demands than we have analyzed.

Interpretation of peak day results for BGP must be different from the two larger systems of LADWP and Edison. Unlike these large utilities, the dominating factor for each city is the small number of units. Should the largest of only three or four available units go out, and even worse, should that unit be the only one with SCR, the options available to each city in meeting a peak day constraint are more limited than the larger utilities. Furthermore, with so few units the NOx emissions on the peak day are unlikely to be normally distributed. Thus simple conclusions based on standard deviations around the mean of NOx emissions are of doubtful statistical validity and dubious policy value for the cities.

In deriving alternative indicators for policy consideration in this situation of few available units, we have examined in more depth the effect on each City of the outage of its large controlled unit in addition to the stress which we have defined on the peak day. Under the assumption that a Rule could have a provision for some sort of automatic treatment for an unscheduled breakdown of a major unit, we have calculated the mean and standard deviation of critical parameters for peak day iterations which exclude these major breakdowns.

The specific major unit breakdowns excluded are:

Burbank:	Olive 1, Olive 2, Pacific Intertie
Glendale	Grayson 5, Grayson 8 combined cycle, Pacific Intertie
Pasadena	Broadway 3

Table 2-3

SCE Emissions At Current Emissions Levels

	(Thousands of Pounds)		(Pounds per MWh)	
Year	2000	2009	2000	2009
Steam Plants	4652	3464	0.71	0.69
Replacements	662	1027	0.15	0.15
Total 1135	5314	4491	0.49	0.38
New Combined Cycle	1290	1359	0.15	0.15
Total In-Basin[1]	6604	5850	0.34	0.28

C. Emissions Control Scenarios

We developed three control scenarios at cost-effectiveness levels of $43,100, $21,100, and $16,400, shown in Figures 2-1 to 2-3 for 2000 and 2-4 to 2-6 for 2009.

At the $43,100 cost-effectiveness level, SCR+UI was found cost-effective for all capacity factors above 7.5%. LNB+UI was generally cost-effective at capacity factors above 3%. UI alone was found cost-effective in a few scattered cases at capacity factors of 1-3%. The level of controls on individual units changed only slightly from 2000 to 2009, with added controls at several Highgrove units (which operated at higher capacity factors due to return from cold standby) and reduced controls at Etiwanda 3 (whose must-run status was changed when a repower or replacement was assumed at Etiwanda 1-2). The average cost of NOx emissions reduction per ton for this control scenario was $22,224 in 2000 and $27,248 in 2009. The higher cost in 2009 results from similar control technologies applied to units running at lower capacity factors.

Annual emissions at this control level are given in Table 2-4. They show a 20% increase in Rule 1135 emissions and a 13% increase in in-basin emissions from 2000 to 2009.

1 Except for Long Beach combined cycle and peakers.

Year
2000

Southern California Edison
Cost-Effective
Emission Control Technologies

< $43,100 limit

	UI	LNB & UI	UI & SCR	Annual Cost ($/year)	NOx Reduction (1000lb) as modeled*	Reduction Cost ($/ton)
ALAMITOS 1	RPR			$0	0.000	$0
ALAMITOS 2	RPR			$0	0.000	$0
ALAMITOS 3				$0	-3.465	$0
ALAMITOS 4	XXXX	XXXX	XXXX	$3,453,585	232.200	$29,747
ALAMITOS 5	XXXX	XXXX	XXXX	$6,740,204	595.035	$22,655
ALAMITOS 6	XXXX	XXXX	XXXX	$6,138,766	725.409	$16,925
EL SEGUNDO 1	XXXX	XXXX		$455,215	41.274	$22,058
EL SEGUNDO 2	XXXX	XXXX		$451,463	53.280	$16,947
EL SEGUNDO 3	XXXX	XXXX		$946,850	92.655	$20,438
EL SEGUNDO 4	XXXX	XXXX	XXXX	$4,235,639	420.228	$20,159
ETIWANDA 1				$0	-1.224	$0
ETIWANDA 2				$0	-1.422	$0
ETIWANDA 3	XXXX	XXXX	XXXX	$3,957,010	263.466	$30,038
ETIWANDA 4	XXXX	XXXX		$840,445	58.302	$28,831
HIGHGROVE 1				$0	-4.986	$0
HIGHGROVE 2				$0	-2.646	$0
HIGHGROVE 3				$0	-4.311	$0
HIGHGROVE 4	XXXX			$35,934	2.826	$25,431
HUNTINGTON 1	XXXX	XXXX	XXXX	$2,408,924	189.036	$25,486
HUNTINGTON 2	XXXX	XXXX	XXXX	$2,388,171	204.345	$23,374
HUNTINGTON 3	RPR			$0	0.000	$0
HUNTINGTON 4	RPR			$0	0.000	$0
REDONDO BEACH 5				$0	-1.683	$0
REDONDO BEACH 6	XXXX	XXXX	XXXX	$2,258,418	286.245	$15,780
REDONDO BCH 7	XXXX	XXXX	XXXX	$5,735,410	485.478	$23,628
REDONDO BCH 8	XXXX	XXXX	XXXX	$5,572,053	478.665	$23,282
SAN BRDINO 1				$0	-2.034	$0
SAN BRDINO 2				$0	-1.386	$0
				$45,618,087	**4105.287**	**$22,224**

XXXX	Cost effective	LNB	Low NOx Burners
:::::::	Borderline	UI	Urea Injection
RPR	Repowered Unit	SCR	Selective Catalytic Reduction

* Calculated Values for NOx reductions were used to determine cost effective technologies. These technologies were then computer simulated to produce "as modeled" reduction values.

Southern California Edison
Cost-Effective
Emission Control Technologies

Year

2000

< $21,100 limit

	UI	LNB & UI	UI & SCR	Annual Cost ($/year)	NOx Reduction (1000lb) as modeled*	Reduction Cost ($/ton)
ALAMITOS 1	RPR			$0	0.000	$0
ALAMITOS 2	RPR			$0	0.000	$0
ALAMITOS 3				$0	-0.792	$0
ALAMITOS 4	XXXX	XXXX		$977,609	148.311	$13,183
ALAMITOS 5	XXXX	XXXX		$2,086,060	390.438	$10,686
ALAMITOS 6	XXXX	XXXX	XXXX	$6,138,766	732.969	$16,750
EL SEGUNDO 1	XXXX	:::::::		$176,965	21.510	$16,454
EL SEGUNDO 2	XXXX	XXXX		$451,463	53.721	$16,808
EL SEGUNDO 3	XXXX	XXXX		$946,850	97.416	$19,439
EL SEGUNDO 4	XXXX	XXXX	XXXX	$4,235,639	420.822	$20,130
ETIWANDA 1				$0	-0.378	$0
ETIWANDA 2				$0	-0.270	$0
ETIWANDA 3	XXXX	XXXX		$1,151,011	172.809	$13,321
ETIWANDA 4				$0	-16.029	$0
HIGHGROVE 1				$0	-4.419	$0
HIGHGROVE 2				$0	-2.079	$0
HIGHGROVE 3				$0	-2.799	$0
HIGHGROVE 4				$0	1.710	$0
HUNTINGTON 1	XXXX	XXXX		$617,015	117.396	$10,512
HUNTINGTON 2	XXXX	XXXX		$609,867	126.234	$9,662
HUNTINGTON 3	RPR			$0	0.000	$0
HUNTINGTON 4	RPR			$0	0.000	$0
REDONDO BEACH 5				$0	-0.666	$0
REDONDO BEACH 6	XXXX	XXXX	XXXX	$2,258,418	286.263	$15,779
REDONDO BCH 7	XXXX	XXXX		$1,739,964	322.902	$10,777
REDONDO BCH 8	XXXX	XXXX		$1,683,697	314.262	$10,715
SAN BRDINO 1				$0	-1.332	$0
SAN BRDINO 2				$0	-0.855	$0
				$23,073,324	**3177.144**	**$14,525**

XXX Cost effective
::::::: Borderline
RPR Repowered Unit

LNB Low NOx Burners
UI Urea Injection
SCR Selective Catalytic Reduction

* Calculated Values for NOx reductions were used to determine cost effective technologies. These technologies were then computer simulated to produce "as modeled" reduction values.

Year
2000

Southern California Edison
Cost-Effective
Emission Control Technologies

< $16,400 limit

	UI	LNB & UI	UI & SCR	Annual Cost ($/year)	NOx Reduction (1000lb) as modeled*	Reduction Cost ($/ton)
ALAMITOS 1	RPR			$0	0.000	$0
ALAMITOS 2	RPR			$0	0.000	$0
ALAMITOS 3				$0	-2.340	$0
ALAMITOS 4	XXXX	XXXX		$977,609	153.900	$12,704
ALAMITOS 5	XXXX	XXXX		$2,086,060	393.930	$10,591
ALAMITOS 6	XXXX	XXXX	:::::::	$1,878,898	467.703	$8,035
EL SEGUNDO 1	:::::::			$0	0.216	$0
EL SEGUNDO 2	XXXX	:::::::		$173,213	26.712	$12,969
EL SEGUNDO 3	:::::::			$0	-40.644	$0
EL SEGUNDO 4	XXXX	XXXX		$1,246,658	271.611	$9,180
ETIWANDA 1				$0	-0.747	$0
ETIWANDA 2				$0	-0.522	$0
ETIWANDA 3	XXXX	XXXX		$1,151,011	172.557	$13,341
ETIWANDA 4				$0	-13.734	$0
HIGHGROVE 1				$0	-4.464	$0
HIGHGROVE 2				$0	-2.241	$0
HIGHGROVE 3				$0	-2.871	$0
HIGHGROVE 4				$0	1.980	$0
HUNTINGTON 1	XXXX	XXXX		$617,015	121.761	$10,135
HUNTINGTON 2	XXXX	XXXX		$609,867	128.457	$9,495
HUNTINGTON 3	RPR			$0	0.000	$0
HUNTINGTON 4	RPR			$0	0.000	$0
REDONDO BEACH 5				$0	-0.936	$0
REDONDO BEACH 6	XXXX	XXXX	XXXX	$2,258,418	286.263	$15,779
REDONDO BCH 7	XXXX	XXXX		$1,739,964	326.484	$10,659
REDONDO BCH 8	XXXX	XXXX		$1,683,697	318.717	$10,565
SAN BRDINO 1				$0	-1.197	$0
SAN BRDINO 2				$0	-0.747	$0
				$14,422,410	**2599.848**	**$11,095**

XXXX	Cost effective	LNB	Low NOx Burners
:::::::	Borderline	UI	Urea Injection
RPR	Repowered Unit	SCR	Selective Catalytic Reduction

* Calculated Values for NOx reductions were used to determine cost effective technologies. These technologies were then computer simulated to produce "as modeled" reduction values.

control scenarios. These increased powerplant emissions are likely to render the District's meeting of NOx control requirements more difficult.

Table 2-8 shows the reductions in total in-basin NOx from electric generation as a result of the cost-effective controls which we modeled. Results for the 1135 System are the same (within rounding error caused by slight changes in combined cycle dispatch). At all cost-effectiveness levels, these results show an erosion in the effectiveness of controls due to increased in-basin generation and NOx emissions from 2000 to 2009 shown above. The erosion in the effectiveness of controls is most pronounced at low cost-effectiveness caps.

Table 2-8

In-Basin NOx Reduction from Electric Generation for SCE
Due to Cost-Effective Controls (Relative to Uncontrolled Case)

	'000 lbs.per year		Tons Per Day		Percent Reduction	
	2000	2009	2000	2009	2000	2009
$43,100 cap	4115	3051	5.6	4.2	62%	52%
$21,100 cap	3186	2025	4.4	2.8	49%	35%
$16,400 cap	2609	726	3.6	1.0	40%	12%

In the extreme case, if the lowest cost control strategy which we modeled is adopted, by 2009 in-basin emissions from electric generation may be reduced by only 12%--slightly less than one ton per day--from a completely uncontrolled case with heavy reliance on in-basin combined cycles.

F. Peak Day Results

We analyzed peak day emissions under a condition of exactly one large nuclear unit out to provide for system stress on the Edison system.

The mean peak day emissions for the years 2000 and 2009 are given in Tables 2-9 to 2-11. The peak day NOx emissions increase significantly from 2000 to 2009 in all of the control strategies, both for the steam units and new combined cycle units, as shown below. While annual emissions from steam plants are reduced from 2000 to 2009 in two of the three control strategies, peak day emissions from steam plants rise from 2000 to 2009 in <u>all</u> control strategies, with a rise of 28% in the $43,100 case, 37% in the $21,100 case, and 20% in the $16,400 case. When increased generation from new combined cycles is also taken into account, peak day emissions of the 1135

CPUC Decision D.93-05-062 and D.94-04-057 TURN versus PacBell

Toward Utility Rate Normalization, Inc., Complainant, vs. Pacific Bell (U 1001 C), Defendant

Decision No. 93–05–062, Case No. 91–03–006 (Filed March 1, 1991)

California Public Utilities Commission

1993 Cal. PUC LEXIS 394; 49 CPUC2d 299

May 19, 1993

Thomas J. Long, Attorney at Law, for Toward Utility Rate Normalization, complainant; Daniel J. McCarthy, Mary Vanderpan, and Michael D. Sasser, Attorneys at Law, for Pacific Bell, defendant; Mary Mack Adu, Attorney at Law, for the Division of Ratepayer Advocates.

PANEL: [*1]

Daniel Wm. Fessler, President; Patricia M. Eckert, Norman D. Shumway, P. Gregory Conlon, Commissioners

OPINION: OPINION

I. Scope of Decision

This decision finds that Pacific Bell (Pacific) violated Public Utilities (PU) Code § 532, a Commission order, and its tariffs in processing customer payments between 1986 and February 1991. We find the violations to be continuous and widespread, to have caused substantial financial harm to millions of customers, and to have resulted in over 7 million improper billings. For at least five years, Pacific's managers knew or should have known about these violations and their resulting harm to Pacific's customers. We also find that Pacific has not properly informed customers of the refunds that may be owed to them.

We herein order Pacific to notify customers fully of its unlawful practices and to offer all potentially affected customers a full refund, with interest. We find that Pacific [*2] still owes its customers $34.32 million in late payment charges and reconnection charges which resulted from its payment processing problems.

Due to the seriousness with which it views these violations, the Commission imposes a penalty of $15 million. Finally, we order an audit of the management of Pacific's customer service operations.

II. Procedural History

Toward Utility Rate Normalization (TURN) filed this complaint March 1, 1991 against Pacific. The complaint alleges that Pacific unlawfully imposed late payment charges and disconnected customers between 1986 and 1991. According to TURN, "Pacific's management was aware of this violation and consciously chose to continue it, to the benefit of Pacific's shareholders and to the great detriment of Pacific's customers." TURN also alleges that Pacific chose not to comply with its tariffs after determining that the associated costs of system improvements outweighed the benefit to Pacific and "failed to consider the cost to customers of improper late payment charges and disconnections."

TURN's complaint seeks, among other things, customer refunds for all improperly collected late payment charges and reconnection charges. [*3] TURN estimates these erroneous charges to be about $33 million. TURN also seeks a shareholder penalty in the amount of $50 million.

The Division of Ratepayer Advocates (DRA) intervened in this complaint to support TURN's allegations. DRA recommends the Commission require Pacific to refund, or apply to other activities, 100% of residential and 20% of business late payment charges collected since 1988, an amount totaling about $94 million. DRA also recommends that the Commission order Pacific to undertake an audit of its operations and commit up to $10 million in overcharges to the Telecommunications Education Trust (TET).

In its response, Pacific admits that it improperly imposed some late payment charges and reconnection charges but states that "an understanding of the circumstances surrounding this issue make it clear that Pacific never intended to improperly charge its customers." Pacific states it took immediate action to remedy the situation by offering refunds to customers and modifying its payment processing operations after the problems were uncovered in February 1991. It estimates outstanding refunds to be about $3 million and objects to any penalty.

After several months [*4] of discovery, hearings were held in this proceeding between July 20, 1992 and August 4, 1992. The matter was submitted on October 2, 1992.

III. The Nature and Extent of the Violations

A. Pacific's Late Payment Charge

We approved a late payment charge for Pacific in Decision (D.) 84-06-111 (Re Pacific Telephone and Telegraph Company *(1984) 15 CPUC2d 232).* There, we found that the purpose of the late payment charge was to provide an incentive for customers to submit timely payments. We authorized a late payment charge in the amount of 1.5%. In so doing, we rejected tariff language proposed by Pacific, expressing our concern that the language was ambiguous regarding the date customer bills would be delinquent and, therefore, subject to late payment charges. We cited an earlier decision which suspended the late payment charge tariff of General Telephone Company of California on the basis that the tariff was ambiguous as to the date a late payment charge would take effect (Bernsley vs. General Telephone Company of California *(1983) 13 CPUC2d 46).* Because we sought precision in the date Pacific's late payment charge would take effect, D.84-06-111 specified tariff [*5] language which provides that a late payment charge would be assessed if received after the "due by" date shown on the customer's bill.

D.84-06-111 estimated the revenues expected from imposition of a late payment charge to be in the amount of $20.4 million annually. Pacific's late payment charge tariff became effective on July 1, 1984. The tariff is consistent with the requirements of D.84-06-111.

B. Pacific's Customer Payment Processing System

1. Overview of the System

Pacific processes customer payments in several steps. When mail is received, it is sorted in one of two Cash Management Centers located in Sacramento and Van Nuys. At those locations, Pacific employees identify various types of mail according to how it must be processed. Mail received in Pacific's company-provided envelopes is sorted mechanically through a bar code sorter which reads the information provided by the bar code on the envelope. Such information includes the late payment charge date and denial notice expiration date (i.e., the date after which Pacific will disconnect service).

Mail which is not sent in one of Pacific's company-provided, bar-coded envelopes is termed "white mail." [*6] White mail is opened and sorted manually. Most white mail payments are forwarded to a computer which records payment and account information. Other types of payments are also processed manually, including those with multiple payments and those which do not have an accompanying payment stub.

Payments, whether they arrive in a bar-coded envelope or are white mail, are either "hot" or "cold." Hot mail requires priority handling because it may be subject to a late payment charge or disconnection. Payments are hot, for example, if they are received within two days of or after the denial notice expiration date, or if they are in excess of $80. "Cold" payments are those for which no company action (e.g., imposition of a late payment charge) is warranted within 3 business days.

After mail is sorted according to type, it is sent through a computer which attempts to reconcile the bill amount with the payment. Subsequently, the payment information is used to update individual customer accounts in the Billing and Order Support System (BOSS). Pacific's customer service representatives, who have contact with customers, use BOSS to obtain the customer account information they need to respond [*7] to customer inquiries. For example, they may determine whether an account is overdue and subject to late payment charges, or respond to customer inquiries regarding account balances. Customer service representatives are located in 60 Business Offices throughout the state.

2. Pacific Considered Many Timely Payments to be Late

Pacific considered many timely payments to be late because of the way it processed customer payments. Pacific did not keep records of the dates it received payments. Primarily because of understaffing, many payments were processed several days — and in some cases several weeks — after receipt. By the time payments were processed, therefore, payments would appear to be overdue.

This problem was particularly acute for white mail and other mail which had to be manually–processed. Unlike mail sent through the bar code sorter, Pacific employees could not determine in advance whether a payment needed to be processed quickly (i.e., was hot) in order to avoid improper company action.

Moreover, Pacific had a policy which provided that white mail could be delayed in processing up to three days. Thus, payments which were timely but which would be overdue [*8] within three days of receipt would be considered late if processing was delayed.

All types of mail and payments were subject to delays in processing and considered late in error. In some cases, mail sent through the bar code sorter was delayed in processing.

Finally, Pacific considered payments received during the 7:00 a.m. pickup at the post office to be "tomorrow's mail." Pacific routinely processed this mail on the following day. Because of this policy, customers effectively had one day less to submit their payments than the tariffs authorized.

3. Pacific's Payment Processing Practices Harmed Customers in Several Ways

Effects on Customers

Since 1986, payment processing delays affected customers in several ways. First and foremost, customers were assessed late payment charges that they did not owe. Late payment charges were assessed at a rate of 1.5% of the customers' bills.

When some payments were considered late, even in error, Pacific would issue temporary disconnect notices. Customers who received them could call Pacific and negotiate a resolution of the payment "problem." If they did not call or receive a call from a service representative, their service [*9] would be disconnected. n1 When customers did call, service representatives did not have accurate information regarding payment receipt dates if payment processing was delayed beyond dates of receipt.

n1 In some cases, service representatives would attempt to reach the customer by telephone prior to disconnection.

In order to avoid a disconnection, Pacific generally required customers to resubmit their payments. In such cases, customers would therefore pay double the billed amount. Some customers stopped payment on their first checks to avoid paying double the amount of their bills. This banking service cost customers $10 to $25. When the customer had stopped payment on the first check, the customer's bank would return the check to Pacific as uncollectible. When this happened, Pacific might erroneously impose a $7 return check charge. Some customers fearing disconnection experienced further inconvenience by having to submit their second payments in person.

Some customers were ultimately disconnected because of delays in payment processing. The cost of reinstating service was $20. In addition, Pacific could require customers to pay a deposit to reconnect service. There [*10] is no way of knowing whether some improperly–disconnected customers did not or could not reinstate service; however, between 1988 and 1992, approximately half of all Pacific customers who were temporarily disconnected for non–payment were permanently disconnected.

In addition to imposing cost and inconvenience on customers, Pacific treated as bad credit risks those customers it erroneously disconnected. Such customers would subsequently have a shorter period in which to pay their bills. With this new status, customers faced a greater likelihood of improper company action in subsequent billing periods.

Because Pacific did not keep records of when payments were received, there is no way of knowing how many customers were affected by delayed payment processing and how they were affected. Examples of customer effects, however, are included in customer complaints and company marketing surveys. One customer routinely mailed his bill ten days before it was due but was routinely assessed late payment charges. One received a temporary disconnect notice and had to submit a second check in person. In that case, Pacific posted both checks and failed to reimburse him for the stop payment [*11] charge. Several customers complained that Pacific informed them that their payments were delinquent or sent them disconnection notices after the customers' checks had cleared their bank accounts. Others who called the company complained that they could not get accurate information about the status of their accounts. One business customer summarized his payment processing problems with the company by commenting "I feel like you're picking on me."

C. Pacific's Managers Knew that Customers were Being Assessed Late Payment Charges and Reconnection Charges in Error

As early as 1986, Pacific managers at all levels knew that customers were being improperly charged and disconnected because of processing problems, as internal documents demonstrate:

A memo dated April 30, 1986 to a third level manager acknowledged that a significant number of erroneous disconnections were occurring each month and that thousands of payments were delayed in processing every month.

A memo dated May 12, 1986 to a fourth level manager acknowledged the regular occurrence of erroneous disconnections.

In 1987, customer service representatives stated concerns over payment posting and furnished their managers [*12] with examples of customer accounts showing related problems.

In late 1987, a customer service representative contacted the Commission regarding payment processing problems. In response, the Commission contacted one of Pacific's vice presidents.

In March 1988, field offices expressed concerns regarding delays in processing payments, leading to the formation of a Cash Management Task Force. Shortly thereafter, the Task Force issued a report finding that erroneous late payment charges were assessed and erroneous temporary disconnection notices were mailed to customers. The report was distributed to numerous managers and line staff.

An April 12, 1990 memo documented delayed payment processing.

An April 17, 1990 report was sent to a fifth level manager. The report documented payment processing delays and effects on customer service. The report stated the delays "impact customer service."

In May 1990, a letter informed three officers, including the Comptroller, of payment processing delays in cash management.

Pacific also had evidence from customers that it was taking improper actions. Between 1986 and 1990, Pacific's management received many customer complaints regarding payment [*13] processing. In 1990 alone, Pacific received 103 complaints which were escalated beyond initial contacts with service representatives to Pacific's executive offices or the Commission's Consumer Affairs Branch. Customers complained that Pacific was "delaying payment processing to be able to obtain late payment charges," that "Pacific holds payments on purpose so that (it) can assess a late payment charge," and that Pacific admitted to two week delays in processing payments.

Pacific also undertook customer marketing surveys. Dozens of customer responses revealed problems attributable to payment processing delays. In response to one customer's inquiry about his payment, Pacific informed a customer that it was "behind in processing the payments." Another who had received a disconnection notice claimed that "somebody in accounts receivable is behind." Another claimed he was having "a problem with unposted payments."

Pacific ultimately remedied the systematic imposition of improper charges shortly after the matter came to the public's attention in February 1991.

D. Pacific Failed to Give Proper Notice of the Overcharges

Shortly after the publication of a newspaper article [*14] on February 3, 1991, Pacific took steps to inform customers that it may have overcharged some customers due to problems with its payment processing system. It did so by issuing press releases to major and secondary media, including newspapers, radio stations, and television stations. It placed large advertisements in several languages in 127 newspapers throughout the state and notified by mail five and one–half million customers who had been assessed late payment charges in 1990. Pacific also issued "fact sheets" in eight languages to over 900 organizations that serve low income customers and customers with limited knowledge of English. It established a toll–free number for customers to call and sent individual letters to over a million business customers.

Pacific's outreach program was truly extensive. However, it did not inform customers as to the full extent of the problems. Its informational materials characterized the problems as "recent" and limited to white mail. Although Pacific's press releases promised that it would return improper reconnection charges, its media advertisements and customer notices did not inform customers of these improper charges. Pacific did not [*15] notify customers that they may also qualify for a refund of returned check charges. Pacific's customer notices did not reach former customers who may have been overcharged or customers who received late payment charges or reconnection charges before 1990.

Some officers and managers who reviewed media advertising about the payment processing problems knew, prior to issuance, that payment processing problems were not limited to white mail payments and that the problems were not "recent," as the notices stated. Some officers who reviewed customer notices understood the wider extent of the problem before the notices were mailed. According to the testimony of Pacific's witnesses, Pacific's media advertising continued almost a month after Pacific's president was aware that the problem extended to payments other than white mail.

E. Discussion

Pacific employed policies and practices which resulted in systematic overcharges between 1986 and February 1991. These overcharges represent tariff violations. Assessing charges which are not covered by tariffs, or which are assessed contrary to tariff provisions, violates *PU Code Section 532* which states:

". . . no public utility shall [*16] charge, or receive a different compensation for any product or commodity furnished or to be furnished, or for any service rendered or to be rendered, than the rates, tolls, rentals, and charges applicable thereto as specified in its schedules on file and in effect at the time. . . ."

Pacific argues that *PU Code § 532* does not apply in this case because, it contends, late payment charges are not a rate for a product, commodity or service. We disagree. In this particular case, late payment charges and reconnection charges are part and parcel of the rates charged for telephone services which are undeniably subject to *PU Code Section 532*. Late payment charges and reconnection charges are, therefore, subject to *PU Code Section 532*.

Moreover, Pacific interprets *PU Code Section 532* too narrowly. *PU Code Section 489* requires that all utility charges and rates must be tariffed or otherwise publicly posted (Re Pacific Bell 1988 *29 CPUC2d 25).* Thus, late payment charges and charges for reconnecting service must be tariffed. We wonder what purpose the code would serve if it required a utility to include its rates and charges in tariffs but relieved the utilities from complying with [*17] those tariffs. We, therefore, interpret *PU Code Section 532* to complement *PU Code Section 489* by providing that the utilities shall not deviate from tariffs required by *PU Code Section 489*. *PU Code Section 532* applies to any tariff rate or other provision. Pacific violated *PU Code Section 532* each time it assessed improper late payment charges and reconnection fees, and disconnected customers in error.

In assessing improper late payment charges, Pacific also violated D.84-06-111. That decision specified that late payment charges may not be assessed on payments received by the date provided on the customer's bill. Pacific's processing standards and practices violated this requirement. Pacific's three-day processing standard for white mail violated D.84-06-111 because under it Pacific would systematically consider timely payments to be late. Pacific's policy to treat mail picked up at 7:00 a.m. as mail received the following day also violated D.84-06-111 because it reduced by one day the amount of time we provided customers to submit timely payments. Finally, every instance in which Pacific delayed payment processing violated D.84-06-111 because Pacific ignored receipt dates [*18] and took action against customers whose payments had been received on time.

IV. Pacific's Defenses for Payment Processing Problems

Although Pacific stipulates that it took improper action against customers, it argues it never intended to harm customers and defends its management response to the problems on several grounds. We find these arguments to be without merit.

A. The Complexity of Pacific's System

Pacific argues that its management did not fully appreciate adverse customer effects in this instance because its payment processing system was complex. According to Pacific, "prior to February 1991 there was a failure to fully understand the adverse customer effects that resulted from the payment processing delays, which was partially attributable to the complexity of the payment processing system."

Pacific's brief and testimony provide substantial detail about Pacific's operations. Neither, however, make a connection between system complexity and management's failure to take appropriate action.

It is incomprehensible that the complexity of the payment processing system was so great that managers did not understand how customers could be harmed by it. The problem [*19] was actually simple. Pacific credited customer accounts on the day payments were processed rather than the day received. Some mail was not processed on the day it was received. Some mail was not even deemed received until the day after it was received. No record was kept regarding the date the mail was received. Accordingly, many timely payments would be considered late in error. The managers who testified for Pacific knew these facts. A newspaper reporter investigated the payment processing problems and explained them in a few short paragraphs. Customer service representatives understood the problems and, to their credit, reported them to management on several occasions. And in spite of alleged system complexity, Pacific cured most of its payment processing problems within days after the matter became public.

The improper actions against customers may have been the result of a complex system, but their cause and effect is not difficult to understand. TURN and DRA observe that these improper actions would not have occurred if Pacific had processed payments on the same day they were received or kept records of the day payments were received.

We cannot excuse Pacific [*20] for ongoing tariff violations on the basis that its managers could not understand the system which they were employed to operate.

B. Pacific's Commitment to Customer Service

Pacific argues the payment processing problems were inadvertent and that it has demonstrated an ongoing commitment to customer service. It points to numerous improvements to its payment processing operations over the past several years, and creation of its Quality Improvement Team (QIT) in February 1991. The QIT analyzed problems in the payment processing system following public awareness of those problems and has undertaken both short term and long term improvements. Pacific also presented an outside consultant to testify that Pacific had responded appropriately to the problems.

Pacific did make changes to the payment processing system between 1986 and February 1991, some of which appear to have been in response to concerns expressed by customer service representatives. Most of these changes were modifications to the BOSS system and to the logic in the bar code sorter (that is, the information the bar code sorter would read). These modifications did not resolve problems involving white mail or [*21] problems associated with more general processing delays. None of the changes fully resolved payment processing problems until after the matter was brought to the public's attention.

Although Pacific made certain system modifications to improve processing, Pacific's managers did not evaluate the effects of those changes on customers. Nothing in the record suggests managers ever asked whether a system change eliminated errors which affected customers. In fact, Pacific's statewide director of customer payment processing testified that "cash management centers had no 'real time' measurement to gather feedback on how their activities were impacting the customer."

Nevertheless, Pacific had enough information before it to resolve payment processing problems, as internal documents show. For example, the 1988 Cash Management Task Force report recommended that Pacific prioritize white mail so that processing hot payments would not be delayed. n2 A letter to the Comptroller in May 1990 recognized that Pacific was taking improper action against customers and quoted a manager who believed that curing the problem may not be "worth spending a lot of money to obtain." In April 1990, employees [*22] recommended that payments be posted on the day received. Pacific failed to implement these or other recommended actions which would have eliminated improper charges and disconnections until after the matter became public. Apparently, Pacific did not wish to incur associated costs.

> n2 Pacific explains that it did not implement the recommendation because it would have taken longer to open and prioritize white mail than it would be to process it. Pacific does not explain why it did not process the white mail as it arrived after it discovered the problems associated with delay.

Pacific argues the QIT will assure tariff compliance in the future. Unfortunately, the need for the QIT arose because Pacific's management did not solve a rather straightforward problem. We have no opinion about whether the QIT will assure future tariff compliance.

We give little credence to the testimony of Pacific's management consultant who found that Pacific's response to payment processing problems was reasonable in light of accepted management practices. The witness did not distinguish between the responsibilities of regulated monopolies and companies operating in competitive markets. We, however,

[*23] do.

The record in this proceeding suggests that the management style at Pacific is largely responsible for the problems which are the subject of this complaint. We take particular note of the problems outlined in the report of Pacific's ombudsman, a report which was drafted following public awareness of the payment processing problems. The ombudsman's report is a candid and unflattering account of the management problems which permitted payment processing problems to continue long after they should have been resolved. The report was based on confidential interviews with dozens of employees at various management and staff levels. n3

n3 Pacific describes the role of the ombudsman as "A confidential channel outside of normal reporting relationships to assist employees who seek direction and guidance regarding matters of perceived improper or unethical conduct." The ombudsman office "provides a safe, neutral environment within the Company for employees to raise issues." The role of the ombudsman, therefore, is to provide a confidential source for employees' concerns, not those of management. In this case, Pacific's officers used the ombudsman office to investigate the conduct of managers and line staff. While we will not second guess this use of the ombudsman's office in this case, we are concerned that management's decision to investigate employee conduct through the ombudsman's office compromises the ombudsman's role. By this, we do not impugn the ombudsman himself who presented a report which obviously required the trust of those he interviewed.

[*24]

Briefly, the ombudsman finds that Pacific "is not meeting its commitments" to its customers. It finds that employees feared management reprisals for identifying legitimate problems, and that they could not discuss problems openly. The report states that managers manage through "fear and intimidation" and that some managers perceived themselves to be "failing" if they escalated a problem to a higher level. The report also found that the internal organizations studied focused on "banked revenues without consideration for impact on customers." n4

n4 The ombudsman's investigation was limited to the people and organizations involved in the late payment processing problems. Whether the problems identified in the report extend to other parts of Pacific's operations is therefore unknown.

Substantiating the ombudsman's report, the record in this proceeding shows that Pacific's managers failed to serve its captive customers according to its tariffs. Of the many internal documents in evidence, those authored by Pacific's managers demonstrate little concern for customer harm. Few even mention customer impacts, and instead emphasize the costs of making system changes. None of the [*25] many internal documents received in evidence refer to tariff requirements. Pacific managers who testified in this case admitted they did not consider whether their processing standards complied with tariff requirements.

Especially disturbing is the testimony of Kendall Murphy, Pacific's Vice President in Charge of Quality, a position which emphasized "improving all aspects of quality of value to customers." Mr. Murphy testified that he was informed in May 1990 about payment processing problems and "inappropriate collection actions" against customers. He testified that he did not understand the significance of these matters and did not inquire further as to their effects on customers even though he appears to have been Pacific's highest level expert and consultant on matters relating to customer needs.

We do not dispute that Pacific generally provides high quality telephone services. In this instance, however, Pacific failed to provide an adequate standard of service as a result of mismanagement. We decline to excuse Pacific's payment processing problems on the basis that Pacific provides high quality service.

C. System Safeguards

Pacific argues that its managers acted [*26] reasonably in this instance because they believed they had implemented "safeguards" in the system designed to prevent customer harm. Pacific includes as a safeguard the use of the bar code sorter to prioritize payments for processing, that is, its ability to identify payments requiring quick processing. A further safeguard, according to Pacific, was the ability of Cash Management Centers to inform service representatives when mail was not processed on the day received so that customer service representatives would suspend action against customers. Pacific notes that customer service representatives could use their discretion to waive late payment charges and disconnection notices when customers appealed action Pacific had already taken.

As TURN and DRA observe, procedures which Pacific characterizes as "safeguards" left substantial room for error. As dozens of internal documents point out, the bar code sorter did not identify hot payments in white mail. Some payments which were processed through the bar code sorter could be, and were, later delayed during subsequent processing. The BOSS messages from Cash Management to customer service employees regarding processing delays [*27] were unreliable and were not used at all prior to 1990. More critically, the BOSS messages did not eliminate improper charges. Their only purpose was to permit customer service representatives to respond to customer inquiries.

The discretion of customer service representatives to waive charges in response to customer inquiries is not a "safeguard." Pacific may not rely upon customers to identify improper charges or disconnections which are systematic. The evidence in this proceeding does not support the view that customers would have any reason to know when they were assessed an improper late payment charge. Customers who suspected improper charges may have chosen not to inquire about them. Even if they had inquired about their billings, customer service representatives did not have accurate information regarding the date payments were received. For these reasons, customer service representatives' discretion to remove charges when customers notified Pacific was not a safeguard.

Internal documents admitted into evidence do not support Pacific's claim that its managers believed they had cured payment processing problems with safeguards. Many of Pacific's key managers had been [*28] informed that customers were being improperly charged and why. To the extent managers in charge were unaware of the facts, their ignorance resulted from failing to ask the most basic questions regarding how the payment processing system affected customers and tariff compliance.

D. Pacific's Customer Notices

Pacific defends the inaccuracies in its media advertising and customer notices by arguing that when these informational materials were drafted the problems with its system were not well understood. Pacific states that it never intended to limit refunds to those customers who had used white mail. It argues that its focus on white mail in its public statements were reasonable because most problems in its payment processing system affected white mail.

Pacific states it has always worked toward refunding as many erroneous late payment charges as possible, and has spent $6 million in its efforts to do so. It also responds to concerns about letters going only to customers who received late payment charges in 1990, pointing out that data base limitations required it to limit notices to those customers or send notices to all customers who had ever received a late payment [*29] charge.

The evidence shows that the information Pacific provided to customers is incomplete and misleading. Customer notices and press releases informed customers that improper late payment charges may have been assessed on customers who did not use Pacific's bar-coded envelopes. The notices failed to mention that improper charges could have been imposed under many other circumstances. The informational materials also suggested that the problems with Pacific's system were "recent" when they were not.

The inaccuracies in Pacific's outreach materials are a source of substantial concern to us. More serious, however, is management's awareness of those inaccuracies. The Director of Revenue Collection Management who had been aware of payment processing problems for several years reviewed customer information which was misleading and allowed its distribution. In addition, Pacific's President, Phil Quigley, and Vice President in charge of regulatory affairs, Gary McBee, knew that processing delays were not limited to white mail prior to the distribution of customer information that led customers to believe the problem was limited to white mail. Mr. Quigley and Mr. McBee reviewed these [*30] customer information materials prior to their distribution. If it was the intent of Pacific to provide truthful and complete information to its customers, it failed to do so. Managers and officers responsible for informing the public of unlawful charges omitted key facts before them and allowed the public to believe payment processing problems were more limited than they were. The effect was to limit the refunds customers would receive.

V. Remedies

A. The Amount of Improper Late Payment Charges and Reconnection Charges

The revenues involved in this case are substantial. Pacific has collected approximately $50 million a year in late payment charges since 1986. This is more than double the amount D.84-06-111 estimated Pacific would collect.

Pacific does not know the actual amounts of overcharges because it did not keep records of the dates it received customer payments. Therefore, Pacific and TURN estimated improper late payment charges and reconnection fees using several models. Pacific estimates about $3.5 million in improper late payment charges between 1988 and January 1991. It does not estimate improper reconnection charges. TURN estimates $33 million in [*31] improper late payment charges between 1987 and January 1991 and believes improper reconnection charges may have been as high as $1.3 million in 1990.

In deriving their estimates, Pacific and TURN make certain assumptions regarding the applicability of the statute of limitations.

1. The Applicability of the Statute of Limitations

In notices to its customers, Pacific offered to refund erroneous late payment charges back to January 1, 1988. In its brief, Pacific retracts this offer by arguing that the statute of limitations in fact bars recovery beyond two years prior to March 1, 1991, the date TURN's complaint was filed.

In arguing that the two year statute of limitations applies, Pacific relies on *PU Code Section 735* which provides that all complaints for violations of the code, except *PU Code Sections 494* and *532*, must be filed within two years from the time the cause of action accrues. We have already found that late payment charges are subject to *PU Code Section 532*. Therefore, *PU Code Section 735* does not apply. Rather, *PU Code Section 736*, which provides a three-year statute of limitations to claims under *PU Code Section 532*, applies.

Pacific is mistaken in assuming [*32] that customers cannot recover improper charges assessed prior to March 1, 1989 (or pursuant to *PU Code Section 736*, March 1, 1988). The statute of limitations is tolled until a plaintiff discovers or should have discovered the facts essential to the cause of action. (*CAMSI IV v. Hunter Technology Corp. (1991) 230 Cal. App. 3d 1525, 1536, Leaf v. City of San Mateo (1980) 104 Cal. App. 3d 398).*

In this case, Pacific's customers cannot be considered to have discovered Pacific's errors until they have been notified of those errors. For customers who might have been improperly charged because they did not use Pacific's bar-coded envelopes (that is, they used white mail), the discovery date would be Pacific's publication of information about this error in February 1991. For customers who were wrongfully disconnected, or who were disconnected and charged for reconnection, or who were charged erroneous late payment charges for reasons other than having sent white mail, the statute tolls until customers have been notified of Pacific's mistake. Customers in those circumstances could not, therefore, have discovered it.

In its reply brief, Pacific suggests that customers did, in [*33] fact, have knowledge about late payment charges, thereby precluding application of the delayed discovery rule cited by TURN. Pacific states bill notices include information about late payment charges. It argues that customers could have called Pacific to determine whether their late payment charges were indeed appropriate.

Pacific may not rely on its customers to identify improper charges and tariff violations. While customers may have known of the policy under which charges would be applied, it defies logic to assume customers knew they were being improperly charged for several reasons. Pacific places the risk of timely post office delivery on customers. Pacific did not notify customers that it had internal billing problems, and some managers appear to have directed service representatives not to discuss known internal problems with customers who took the initiative to ask. Some service representatives may have reversed the charges of some inquiring customers. Millions of other customers, however, did not receive refunds and cannot be reasonably assumed to have known about the improper charges. Indeed, Pacific would hold its customers to a standard to which it would not [*34] hold its own officers and managers: it seeks to avoid liability in this complaint by claiming officers and managers were ignorant of payment processing problems while asking us to assume that its customers should have known about the same problems. Pacific cannot have it both ways.

Where a utility knew or should have known that it was overcharging its customers, the benefit of the doubt must go to customers. It would be patently unfair to interpret the statute of limitations to bar customers from claiming reparations for acts of which they had no knowledge. Pacific has acknowledged that it erroneously charged customers and the evidence shows that the errors were committed as far back as 1986. We interpret the statute of limitations in this case to require customers to make a claim within three years following discovery. (Independent Consulting Services vs. Pacific Bell *(1986) 21 CPUC2d 181).* Pacific will be ordered to refund to customers overcharges imposed as far back as 1986.

To summarize, the three-year statute of limitations takes effect in February 1991 for customers who were assessed late payment charges and did not use Pacific's bar-coded envelopes. The three-year [*35] statute of limitations becomes effective for disconnections and late payment charges for customers who did not use white mail on the date customers are notified by Pacific of their rights. From those dates, customers have three years to claim reparations. Their claims of damages may go back to 1986.

2. Pacific's Models. Pacific estimates that erroneous late payment charges for the period January 1988 to February 1991 are between $3.5 and $3.9 million. Pacific used two types of models to estimate these erroneous charges. First, it used a regression model which sought to determine charges before and after it modified its system to eliminate improper charges. The difference would be the improper charges. The regression model adjusts for such effects as changes in customer behavior, the size of the customer base, economic changes and the seasonal variations in late payment charges. Pacific used actual data separately for residential and business customers. Pacific defends use of its model, pointing to evidence that the recession began in mid-1990 in California and not at a discrete moment in February 1991, as TURN must assume in its analysis.

Pacific also used what it calls [*36] a "carryover/slacktime model" to estimate improper charges. "Carry over" is the number of days mail went unprocessed. "Slack time" is the number of days mail could tolerate delays before improper charges would be assessed. Pacific states this study supports its analysis that most improper late payment charges are in the business sector, finding that most white mail was from business customers. From this study, Pacific estimates that about 3.7% of all late payment charges may have been erroneous.

Pacific also uses raw data to show that business late payment charges fell sharply after February 1991 and that residential late payment charges did not.

DRA would have the Commission ignore Pacific's carryover/slacktime analysis on the basis that the accuracy of the raw data is suspect. For instance, DRA criticizes Pacific's exclusive use of 1990 data, stating that Pacific itself has argued that the late payment charge problem improved over the years. If this is so, argues DRA, 1990 data underestimates erroneous charges in earlier years. DRA also questions the estimate derived from the study showing that 29% of bills were assessed late payment charges. Pacific's data, according [*37] to DRA, shows this number is substantially higher than the charges actually imposed, amounts which hover around 20% during 1989 and 1990.

DRA and TURN are especially critical of the regression model's failure to capture effects of the recession, which would tend to increase late payment charges in the "after" period and thereby underestimate the erroneous late payment charges in the "before" period. TURN argues that Pacific's model is counterintuitive because it predicts that the residential sector was overcharged only $90,000: TURN points outs that Pacific has already refunded over $1 million to the residential sector as a result of its outreach program. TURN also argues that Pacific's model illogically predicts that late payment charges would increase as income increases.

3. TURN's Model. Using Pacific's business model as the basis for its own regression analysis, TURN estimates that $3.06 million of business late payment charges were erroneous. TURN argues that the business model does not have the statistical problems of Pacific's residential model and, therefore, believes it appropriate to apply the estimates of the business model to residential effects. TURN states [*38] the business model may be applied to residential customers, even though the classes of customers may behave differently, because the Commission needs to determine how Pacific behaved toward its customers and not customer behavior. TURN states that since 3/4 of outreach refunds have been to residential customers, it is reasonable to assume that business and residential customers were equally affected by improper charges. TURN argues this estimate is supported by a Pacific study showing that white mail volumes for both sectors were about the same.

To its basic estimates, TURN adds amounts to account for erroneous late payment charges in 1987, subtracts amounts which have already been refunded, and adds interest at 11.5%. TURN's final estimate of improper late payment charges is $33.46 million.

Pacific argues that TURN's estimates were subject to statistical errors and are, therefore, unreliable. Pacific also challenges the use of business equations to extrapolate residential effects because the payment patterns of the two sectors are different. Pacific states that TURN's criticisms of Pacific's models apply equally to the business equation TURN uses.

Pacific also points out that [*39] TURN erroneously assumes that almost half of late payment charges were assessed to residential customers, contrary to data suggesting that business customers paid the bulk of the erroneous charges.

4. Discussion. In estimating improper late payment charges, the parties relied primarily on regression models. Such models may be useful estimating tools. However, they are reliable only to the extent their underlying assumptions are

correct, the data is sound and complete, and variables are not influenced by exogenous effects or by other variables. The several experts who presented testimony on regression models in this proceeding disagree on the nature of model shortcomings, the importance of questionable statistics, and the very assumptions under which the models were developed.

Using regression analysis to estimate how changes to Pacific's payment processing system affected the imposition of late payment charges presents difficult challenges. Regression models in this context require the analyst to assume too much about how the recession, for example, has affected customer behavior, how seasonal variations influenced payment processing, and how business customer behavior [*40] compares to that of residential customers. The fact that the models of Pacific and TURN produce such differing results confirms our view that we cannot rely much on either.

Pacific's carryover/slack time is a simpler model. It is in some ways unsophisticated, but has intuitive appeal and does not require controversial assumptions or complex statistics. We believe we can reasonably rely on this model as a basis for estimating improper late payment charges. The model does, however, require certain adjustments. First, the carry over/slack time model only estimates improper charges back to 1988. The record in this proceeding shows the payment processing problems began in 1986 and that the matter was raised with management in 1986. We will, therefore, modify the model's estimates to incorporate overcharges back to 1986. In so doing, we use Pacific's 1990 overcharge estimate as the base for other years and other adjustments.

Second, as DRA points out, the model assumes illogically that improper late payment charges in 1988 and 1989 were about equal to those assessed in 1990. This assumption is contrary to the testimony of Pacific's witnesses to the effect that the late payment [*41] charge problem abated over time. The model, therefore, requires modification to recognize that improper late payment charges decreased between 1986 and 1991. Pacific does not estimate the extent to which the improper charges decreased over the years. Under these circumstances, we are required to use judgment, and we infer that the number of late payment charges decreased each year by 20% between 1986 and 1990. Therefore, the 1986 estimate will be considerably higher than the 1990 base amount. The estimate will fall each year following 1986 by 20%. We will modify the model accordingly.

Third, we add interest to the amounts in question. Pacific argues that it did not add interest to refunds for improper charges because its tariffs do not provide for interest. n5 We have found that interest shall be paid where the utility has had the use of complainant's money, consistent with *PU Code Section 734* which provides that reparations shall be paid with interest (Wright's Stationers v. Pacific Bell *(1990) 37 CPUC2d 464)*. A logical estimate of the value of the funds held by Pacific is its rate of return. Pacific's rate of return is well below its customers' short-term cost of money [*42] which is best measured by the interest rate on their credit card purchases. To simplify the calculation, and calculations of refunds to individual customers, we will use 12% as a reasonable proxy for Pacific's actual rate of return in each year. n6

n5 We find it ironic that Pacific asserts it has no tariff authority to pay interest on charges which were assessed without tariff authority.

n6 This amount is below Pacific's authorized rate of return in some years and above it in others for the period 1986 through 1991. Pacific argues that the 90-day commercial paper rate is the rate used by the Commission and should be used here. However, we use that rate where interest may accrue to either the utility or its ratepayers. To provide such symmetry in this case argues for an interest rate of 18%, which is the rate Pacific charges for late payments.

Finally, we subtract amounts Pacific has already refunded to customers. That amount is $1.96 million. The foregoing calculation is presented graphically in Table 1.

After making these adjustments to Pacific's model, the estimated overcharges for the period between 1986 and January 1991 is $24.14 million. Exclusive of interest, [*43] this is about 5% of the total estimated late payment charges assessed between 1986 and January 1991, compared to Pacific's estimate of 3.7% and TURN's estimate of about 10%. n7 The amount also falls between the estimates provided by TURN and Pacific using several different analyses.

n7 We assume based on the record that Pacific collected about $50 million per year in late payment charges.

The estimate we derive today is conservative for several reasons. First, Pacific has already refunded about $2 million. This amount is higher than our 1990 base estimate of $1.64 million. The amounts Pacific has refunded could be considerably less than actual overcharges for that period for several reasons. Pacific did not inform customers as to the extent of improper charges (that is, customers were left with the impression that late payments charges may have been improperly assessed only if customers used white mail). In addition, refunded amounts probably only reflect improper charges imposed in the recent past because Pacific's press releases stated that the problem was "recent." Finally, it is reasonable to assume that many customers who may have been owed refunds did not pursue them [*44] because amounts for individual customers were in many cases very small and not worth their effort. n8

n8 A late payment charge on a $50 bill is $.75.

The model is also conservative because it assumes that 29% of payments during the period in question were actually late. This assumption is at odds with experience: in 1990, the actual number of late payments was about 20%. Using Pacific's higher estimate of 29% biases the estimate of improper late payment charges downward.

Finally, we consider our estimate to be conservative because it is less than the upper estimate presented by Pacific's own witness. Pacific's witness testified that using his analysis, improper late payment charges, exclusive of interest, could have been as high as $13.3 million for the period January 1988 through February 1991. n9 Our estimate for the same period is less than $8 million, exclusive of interest.

n9 Pacific's witness pointed out that the probability of this estimate being correct is very small, using his regression model.

In addition to estimating improper late payment charges, we must also estimate improperly assessed reconnection charges. The record in this proceeding provides little [*45] guidance regarding the extent of improper reconnection charges. TURN estimates that improper reconnection fees during 1990 were in the range of $.7 million to $1.3 million. Pacific does not provide a reasonable analysis of its own n10 or refute TURN's estimate. We find, therefore, that the low end of TURN's estimate is a reasonable base. We use the low end to recognize that Pacific's customer service representatives may have waived the charge for inquiring customers and that customers were more likely to inquire about a $20 reconnection charge than a much smaller late payment charge. To derive total improper reconnection charges, we apply the same principles used in estimating late payment charges, that is, we increase the number of improper charges each year back to 1986 and add interest at a rate of 12%. This calculation results in an estimate of improper reconnection fees in the amount of $10.19 million. The calculation is presented graphically in Table 2.

n10 Pacific's regression analysis showed that no reconnection charges were improperly assessed. Because this result is contrary to the testimony of Pacific's own witnesses, the regression analysis is unworthy of consideration. [*46]

The total dollar amount of improper late payment charges and reconnection charges is a substantial sum. It is tiny, however, compared to the charges collected by Pacific over the five–year period which for late payment charges alone appears to exceed $250 million. Moreover, the overcharges we estimate today are much less than the late payment charge revenues Pacific has collected in excess of estimated revenues. D.84–06–111 forecast the amount to be approximately $20 million annually. Pacific has collected over $50 million annually. Finally, our estimate of overcharges does not include other costs which customers incurred as a result of Pacific's payment processing problems. Those costs include return check charges ($7), stop–payment charges (which averaged $25 for business and $10–12 for residential customers), and those associated with billing inquiries. n11

n11 Pacific's press releases originally stated Pacific would refund return check charges, although subsequent informational materials did not.

In sum, we estimate improper late payment charges for the period 1986 to February 1991 to be $24.14 million, and improper reconnection fees to be $10.19 million. We will [*47] direct Pacific to place these amounts in an interest bearing account from which it shall withdraw future customer refunds.

B. Disposition of Unrecovered Refunds

Although no party raised the issue in this proceeding, we must address the disposition of unrecovered refunds (as distinguished from amounts which are considered penalties or fines). Under the Unclaimed Property Law, unclaimed refunds of late payment charges and reconnection charges must be delivered to the Controller of the State of California (*Cory v. Public Utilities Commission (1983) 33 Cal. 3d 522).*

Consistent with the Unclaimed Property Law, we will direct Pacific to deliver to the Controller unrecovered refunds soon after the statute of limitations lapses. The statute of limitations lapses at different times for customers who used white mail and those who did not. Although we are unable to estimate precisely different amounts for those two types of refunds, we believe it reasonable to require Pacific to deliver to the Controller half of the balance in the account in February 1994 (after which time customers who used white mail would be barred from recovering refunds). The other half shall be delivered [*48] to the Controller three years following customer notices required by this decision.

Because unclaimed refunds escheat to the state and may not be used to reduce the rates of customers, we do not need to determine the ratio of overcharges to business customers to residential customers.

C. Customer Notification

Pacific's outreach program was grossly inadequate. From our review of the information Pacific sent to its customers, we find that many customers who may have been overcharged have not been informed of their rights. As DRA recommends, customers should be notified that:

Late payment charges were improperly assessed as early as 1986 and that customers still qualify for refunds;

They may have been improperly disconnected and charged improper reconnection charges;

Improper late payment charges and disconnections may have occurred for any type of payment, including payments mailed in bar-coded envelopes provided by Pacific;

They may qualify for a refund of returned check charges or stop-payment charges.

We will direct Pacific to notify customers, including those who have not used Pacific's services since 1986, of these matters. It shall consult with TURN and DRA before [*49] submitting the notices to the Public Advisor's Office for review and approval.

D. Imposition of Penalties

TURN recommends a penalty in the amount of $50 million arguing that Pacific in this case has failed to grasp management's responsibilities to its customers. TURN believes Pacific did not learn the lesson of the marketing abuse case, where the Commission fined Pacific $16.5 million. TURN comments that $50 million is roughly 3% of Pacific's $1.5 billion in profits during 1990. DRA further comments that it should be Pacific's burden to substantiate any unrefunded late payment charges. Its proposal to require Pacific to refund all residential late payment charges and a substantial percentage of business charges imposed since 1987 is, in effect, a proposal for a penalty.

Pacific believes no penalty is warranted in this case. Pacific explains that its errors were unintentional and that it took immediate corrective action once it was fully aware of the problem. Pacific comments that the Commission has used penalties in the past to deter future similar conduct and avoid unjust enrichment. In this case, Pacific argues, it has not only addressed immediate problems but also [*50] created the QIT to develop long-term solutions to payment processing problems. Pacific believes it has not been unjustly enriched in this case, bearing the expense of corrective action and $6 million in administrative costs.

1. Applicability of *PU Code Section 2113*

TURN argues that we are within our authority to redress this serious matter within the terms of *Section 2113 of the Public Utilities Code*. In pertinent part this legislation provides:

"Every public utility, corporation, or person which fails to comply with any part of any order, decision, rule, regulation, direction, or requirement of the commission or any commissioner is in contempt of the commission, and is punishable by the commission for contempt in the same manner and to the same extent as contempt is punished by courts of record. . ."

Courts of record may fine individuals or entities up to $1,000 per incident for contempt.

Pacific does not dispute the Commission's authority under Section 2113 but argues that a finding of contempt should require a showing beyond a reasonable doubt of willful violations. As TURN points out, however, the courts' definition of "willful" does not require that the defendant [*51] display a "deliberate intention," but need only demonstrate an "indifferent disregard" of duty. In re Burns, Cal. App. 2d 137, 142 (1958). More recently, we held that a defendant cannot escape a finding of contempt "by lack of diligence or by avoiding knowledge of the utility company's operations" and especially where "if ordinary diligence had been exercised, knowledge of the unlawful actions could have been reasonably obtained." In re Hilliard, *80 CPUC 318, 320 (1976).*

The concept of contempt has long resided within the equity powers of judicial authority. The legislature surely knew this when, in 1911, it first enacted the predecessor of current Section 2113. The essence of equity is discretion and the ability to balance the provocation with an appropriate response. In this context the factors which influence an exercise of discretion are mixed but, in our judgment, ultimately counsel against proceeding under the aegis of Section 2113. We have no evidence to suggest that Pacific intended to defraud its customers or to violate its tariffs. While evidence of deliberation is not required, its absence is a factor which we do not overlook. Taken against this is the [*52] clear evidence in the record that Pacific's managers and officers did not exercise ordinary diligence in responding to this serious abuse of customer trust. Pacific's managers were aware of payment processing problems as far back as 1986 and failed to take action sufficient to remedy those problems. This is an unhappy record which could, within the Burns/Hilliard precedents; be equated with a contempt finding. Our refusal to do so is premised upon three factors. First, we regard a citation for contempt as an ultimate exercise of our authority warranted only in the face of the most glaring provocation. Second, we are mindful of the need to promote a climate in which business may advance the prosperity of California, a climate which may well warrant a tempering of governmental fines and exactions. Finally, we are confident that Section 701 is a more than adequate source of authority to fashion a fine warranted by this record.

2. Applicability of *PU Code Section 701*

In numerous cases we have utilized Section 701 as the basis for imposing penalties to remedy a failure to observe our orders, decisions or tariffs. *PU Code Section 701* provides that the Commission may do "all [*53] things . . . which are necessary and convenient in the exercise" of its power and jurisdiction. Under that authority, we recently found that Pacific would be subject to fines if it engaged in anti–competitive contract pricing (D.91–07–010). We have also implicitly used this authority to impose a penalty in the Pacific "marketing abuse" case (Re Pacific Bell *(1987) 27 CPUC2d 1, 36)* and to adjust rates of return in cases where service quality was found to be inadequate (Re General Telephone *(1980) 4 CPUC2d 428,* Re Pacific Telephone and Telegraph *(1976) 80 CPUC 599).*

We are therefore within our authority under *PU Code Section 701* to impose penalties on Pacific.

3. Discussion

An important role of this Commission is to assure that jurisdictional utilities provide adequate customer service, especially to customers who have no service options. To this end, we set standards, require tariffed offerings, and enforce the rules we promulgate. Our authority to enforce rules, standards, and tariffs extends beyond what we can accomplish with dicta or directives. We have used this authority to impose penalties on many occasions.

In D.86–05–072, we found that Pacific had [*54] violated its tariffs in several respects because of the way it marketed nonessential services to monopoly customers. Among other things, Pacific improperly denied Lifeline service to qualified customers, packaged discretionary services with basic service and failed to inform customers of these extra services, and required deposits of customers who qualified for a waiver of deposits. We took several actions to mitigate the effects of these infractions, including an order to cease "cold calling" practices, to correct bill inserts and to train employees regarding the Lifeline program.

Our concerns over these marketing practices also led to the imposition of a $16.5 million penalty which has been used to fund a telecommunications education program called the Telecommunications Education Trust; the creation of the Customer Marketing Oversight Committee which would monitor future marketing practices, and; workshops to develop appropriate customer notification. *((1986) 21 CPUC2d 500,* and *(1987) 27 CPUC2d 1.)*

Later, the Commission issued D.88–11–028 in which it found that Pacific had marketed Touchtone service to customers served by end offices which did not have the technical capability [*55] to provide Touchtone service. Some customers, therefore, paid for a service which was not available to them. We directed Pacific to refund these improper charges to Touchtone customers in areas served by end offices without Touchtone capability.

Recently, CACD determined that Pacific had in some offices routinely refused to refund amounts owed to customers which were less than $5.00, a policy which was not the subject of tariffs.

In this case, Pacific states the Commission should impose penalties only where they are required to deter future similar conduct and avoid unjust enrichment. Pacific argues further that a penalty is not required to accomplish either of these ends in this case. n12

n12 Neither deterring future wrongful activity nor assuring against unjust enrichment is a prerequisite to a finding of contempt under Section 2113 (Dyke Water Company *(1964) 63 CPUC 76,* Air California v. Pacific Southwest Airlines *(1969) 70 CPUC 213.)*

We do not know whether Pacific would be unjustly enriched absent a penalty in this case. Pacific has presented no plan for refunding overcharges which are still owed to customers. Presumably, Pacific would retain any overcharges [*56] that are unclaimed. Accordingly, if TURN had not filed this complaint, Pacific might have been unjustly enriched. This decision estimates overcharges which are still owing to customers and directs Pacific to inform customers of their rights. Although we will never know whether the estimates we adopt today fully recover the overcharges imposed on customers, in theory at least, no unjust enrichment will occur. n13

n13 The expense Pacific has incurred or will incur to mitigate the damage to customers does not enter into our calculation of whether Pacific might be unjustly enriched. That expense was incurred as part of a duty to inform its customers of improper charges and would not have been necessary if Pacific had not violated its tariffs.

Whether a penalty is required to deter future mismanagement is a matter for pure speculation. Pacific believes the QIT will assure against future problems. Based on past experience, we are not so confident. Following discovery of Pacific's marketing abuses in 1986, several organizations were created to guard against future problems, among them, the Ethics Advisory Council, the Office of Business Conduct and Standards and the Customer [*57] Marketing Oversight Committee. None of these organizations protected customers against the abuses we review here today. We cannot assume that the QIT will accomplish what these organizations could not do.

In general, Pacific's witnesses leave the impression that they believe the subject payment processing problems and tariff violations are minor concerns. Pacific defends itself against this complaint by arguing that tariff violations were simply the result of management ignorance and a complex operation. These, however, are not defenses. They are admissions of considerable mismanagement.

Several of Pacific's managers and officers were aware that customer notices and media advertising did not tell the whole story about payment processing problems. While we do not have evidence that Pacific intended to deceive customers, the effect of management's negligence was to limit the amounts of overcharges customers would claim.

In recent years, we have emphasized the importance of regulatory incentives and we must consider them here. The tariff violations reviewed in this proceeding and the circumstances which surround them are serious matters. If we were to overlook them, we would [*58] send a message to Pacific and every utility we regulate that the only risk associated with ongoing tariff violations would be the risk of having to return overcharges in the event they were discovered. This is not the type of incentive we wish to provide.

With this in mind, we today order Pacific to pay a substantial penalty of 15 million dollars. The intent of the penalty in this case is to signal Pacific's management and shareholders that we will not countenance customer service problems and tariff violations that are systematic. It should serve as a warning that Pacific's management style, as it has been portrayed in this complaint, is incompatible with Pacific's role as a provider of an essential monopoly service. In addition, we apply a penalty because Pacific's managers supervised the release of information which failed to provide known facts regarding customer rights and Pacific's culpability.

We also consider the penalty in the broader context of our regulatory oversight. In the past, we reviewed customer service issues in general rate case proceedings. In those proceedings, we directed service changes where necessary and considered customer service in calculating [*59] adopted rates of return. In D.89-10-031, we eliminated general rate case reviews for Pacific believing that Pacific would manage its resources better with the financial incentives we adopted in the "new regulatory framework." Under the new regulatory framework, the general rate case no longer exists as a forum for customer representatives to lodge service quality complaints: they must now initiate complaints such as the one before us. Nor is the general rate case any longer a forum for our consideration of how service quality should affect the adopted rate of return.

Our reduced regulatory oversight does not signal that customer service matters are less important. We will continue to oversee service quality and expect an unfailing attention to tariff requirements and customer needs. Today's decision should signal our regard for high quality service under any regulatory regime.

We consider the disposition of the penalty in light of those customers most likely to have been harmed by Pacific's payment processing problems. Customers who may have been charged and who were least likely to have understood that they qualified for refunds are those customers who are least familiar with [*60] utility services and those for whom English is a second language. More seriously, some customers may have been erroneously disconnected who could not afford the cost of reinstating service. Customers in these types of circumstances suffered disproportionately. Pacific's payment processing problems also affected the availability of telephone service to low income customers. For this reason, we today direct Pacific to set aside one half of the penalty for the sole purpose of funding connection charges imposed on low income customers who qualify for Lifeline service.

The remaining half of the penalty will be used to reduce the rates of all customers. Pacific is ordered to reduce rates to its basic service customers by $7.5 million, plus interest, (The interest rate used should be 12%, consistent with the interest rate applied to the refunds. This 12% interest rate is explained in prior sections of this order.) which should accrue beginning the effective date of this decision. This reduction should be implemented over a one-year period in Pacific's next annual price cap filing. The amount should be applied as an exchange surcredit to the rates of all classes of customers.

Finally, [*61] we observe that we have not in this proceeding investigated the specific changes Pacific made to its payment processing operations and how they might affect tariff compliance in the future. We trust, based on Pacific's assurances, that it has cured the payment processing problems which are the subject of this proceeding. We put Pacific on notice that any future problems with its payment processing system will motivate us to suspend Pacific's authority to impose late payment charges. If we take such action, Pacific should expect to absorb associated lost revenues.

E. Other Recommended Action

DRA recommends the Commission order Pacific to use unrefunded overcharges to accomplish the following:

To fund an independent audit of Pacific's internal communication, accountability and control processes, and to advise Pacific and the Commission regarding organizational deficiencies which remain to be addressed;

To fund an inter-organizational committee, including representatives of Pacific's business office and management, staff from the Commission Advisory and Compliance Division and DRA, and consumer organizations, to review the findings of the audit and the QIT to ensure that [*62] root organizational problems are remedied;

Up to $10 million to fund an effort on the part of the TET for the purpose of informing Pacific's customers as to how to raise issues regarding service quality or improper collection action at Pacific or the CPUC.

As DRA suggests, a management audit of customer service related functions would be helpful in preventing future problems of the sort we have considered today. An audit would also facilitate review of customer service issues in our tri-annual review of Pacific in Application (A.) 92-05-002. We will direct an audit to analyze whether Pacific's management style permits open communication and problem-solving. It should assess the extent to which Pacific's management promotes attention to service to its monopoly customers and the role of cost-cutting as it may affect monopoly services. In this regard, we would like to know how Pacific should improve its management practices. The audit should consider all customer-service related functions within Pacific. We will direct CACD to supervise the audit, which shall be undertaken by independent consultants. We will direct the results of the audit to be submitted and reviewed in A.92-05-002. [*63]

The management audit we order today, and our review of it in A.92-05-002, obviate the need for the creation of the oversight committee DRA recommends. Further, we are not prepared at this time to direct additional funding to the TET for the primary reason that we have no evidence in this proceeding that such funding is necessary. Specifically, we have no evidence that Pacific's customers are poorly-informed about how to raise concerns about service quality or improper collection action with Pacific or the Commission.

As discussed earlier in this decision, state law requires that unclaimed utility refunds escheat to the state. Therefore, we cannot order Pacific to use unclaimed refunds for the purposes DRA proposes. However, we are within our authority to require Pacific to undertake and fund activities such as DRA proposes. We will therefore direct Pacific to fund the audit we order today.

VI. Intervenor Funding

On July 3, 1991, TURN filed a Request for Finding of Eligibility for Compensation. It states its intent to seek funding, should it prevail in this complaint, from one of three sources (1) a common fund of reparations or other sums that may be generated as a [*64] result of this complaint; (2) the Advocate's Trust Fund; or (3) intervenor fees authorized under Article 18.7 of the Commission's Rules of Practice and Procedure.

Although at the time of filing TURN was unsure which of these three options would be most appropriate in this case, it made its filing under Article 18.7 which provides procedural guidance where the other options do not. Under Rule 76.54 of Article 18.7, TURN must provide (1) a showing of significant financial hardship as a result of its participation; (2) a statement of issues to be raised in the proceeding; (3) an estimate of compensation to be sought; and (4) a budget for the participation.

TURN has already been found to have met its burden of showing financial hardship for calendar year 1991 in D.91-05-029. At the time of its pleading, it had raised pertinent issues in its complaint. TURN estimates the cost of its participation to be approximately $104,000. Its estimate assumes 400 hours of attorney time at an hourly rate of $160, 200 hours of time for a consultant at an hourly rate of $100, and $20,000 for related costs, such as the costs of depositions, copying, and postage. This information satisfies the requirements [*65] of Rule 76.54. We will grant TURN's request for a finding of eligibility for compensation.

In 1992, the Legislature enacted AB 1975 which modifies sections 1801-1813 under which we grant intervenor funding. We have not yet promulgated rules to replace those in Article 18.7 and which would complement the legislation. However, the procedural steps used by TURN, and set forth in Article 18.7, are appropriate in this case.

Prior to enactment of AB 1975, TURN would not qualify for intervenor funding under Article 18.7 because those rules provided for intervenor funding only in cases where participation affects a utility rate. This case does not affect a rate, but rather issues related to customer service. Under AB 1975, however, funding is no longer limited to proceedings which affect tariffed rates. TURN may seek funding under AB 1975 in this complaint.

TURN may also be eligible for compensation from the common fund of reparations created by this order. That is, TURN's fees could be drawn from the account established by Pacific for customer refunds or from the penalty imposed on Pacific. Another funding source — The Advocate's Trust Fund (Trust) — was established to fund [*66] participation in quasi-judicial proceedings such as this complaint. The Trust was established to fund participation in proceedings where no other funding is available. In this case, there exists other funding. The Trust, therefore, is not an appropriate funding source in this complaint.

In sum, we find TURN eligible for compensation in this proceeding. It may seek compensation from the common fund created by this decision or pursuant to Code Sections 1801-1813.

VII. Conclusion

This proceeding has reviewed tariff violations by Pacific which occurred in processing customer payments over a period of several years. Pacific admits to the violations, although it believes it should not be penalized for them.

We are aware that the management of a company as large as Pacific is complicated and difficult. We are also aware that changes in telecommunications markets and technologies may further complicate Pacific's operations. These circumstances do not, however, excuse Pacific from systematic tariff violations. Pacific has been entrusted to provide most of the state's residents and businesses with a basic and critical form of communication. It must do so with unrelenting attention [*67] to its tariffs and the needs of its customers.

To help assure that we will not revisit customer service problems again, we today impose a $15 million penalty on Pacific. We do so with the belief that the penalty will send a message to shareholders and management that we expect Pacific to provide the highest quality service in accordance with its tariffs and consistent with its obligation to serve the people of the state.

Findings of Fact

1. D.84-06-111 specified that Pacific's late payment charge would be assessed, and an account may be subject to disconnection, if a customer payment is not received on or before the due date shown on the customer's bill.

2. Pacific's late payment charge tariffs specify that a late payment charge will be assessed, or an account may be subject to disconnection, if a payment is not received on or before the due date on the customer's bill.

3. Pacific credits payments to customer accounts on the day a payment is posted to the customer's account rather than the day the payment is received. Between 1986 and 1991, some payments were delayed in the posting process and were, therefore, considered late in error.

4. When Pacific considered [*68] timely payment to be late in error between 1986 and 1991, it improperly assessed late payment charges and/or disconnected its customers.

5. Since 1986, the problems with Pacific's payment processing system were the subject of customer complaints, internal investigations, and expressions of concern by certain employees.

6. Since 1986, Pacific managers were aware of payment processing problems which resulted in erroneous company actions against customers.

7. The imposition of improper charges and disconnections came to the attention of the public in February 1991.

8. Pacific resolved its payment processing problems shortly after the matter became public.

9. Pacific's customers were not informed about Pacific's errors with regard to "white mail" payments until February 1991.

10. Pacific has not notified its customers of erroneous charges and disconnections which occurred for reasons other than the use of "white mail" to make payments.

11. Pacific's press releases and customer notices have left the impression that payment processing problems were recent, although they began in 1986.

12. Pacific has not notified customers who are no longer on its system of the late payment [*69] processing problems.

13. Certain managers and officers who reviewed customer notices and press releases were aware that the extent of payment processing problems was greater than the customer notices and press releases stated and that the period during which those problems occurred extended beyond the "recent" past.

14. Late payment charges and reconnect fees are tariffed as part of other services.

15. Pacific violated its tariffs when it improperly imposed late payment charges and disconnected customers.

16. The problems associated with Pacific's payment processing system were not so complex that Pacific could not have resolved them before February 1991.

17. Pacific undertook improvements to its payment processing system between 1986 and 1991 but those improvements did not resolve problems which resulted in improper charges and disconnections.

18. The record in this proceeding suggests Pacific imposed improper charges and erroneously disconnected customers because of a management style which emphasizes company profits ahead of customer service.

19. The "safeguards" against erroneous late payment charges which Pacific's managers perceived did not adequately protect customers. [*70]

20. Pacific estimates unrefunded erroneous late payment charges to be between $3.5 million and $3.9 million, exclusive of interest, for the period January 1988 to February 1991.

21. TURN estimates unrefunded erroneous late payment charges to be $33.46 million, including interest of 11.5%, for the period January 1987 to February 1991.

22. The regression analyses presented in this proceeding were controversial and arrived at widely differing estimates of improper late payment charges.

23. Pacific's slacktime/carryover model provides a reasonable basis from which to estimate overcharges.

24. The slacktime carryover model does not estimate total improper late payment charges because it does not estimate overcharges to 1986, fails to account for decreasing overcharges since 1986, and fails to include interest.

25. Pacific had, at the time testimony was submitted in this proceeding, refunded approximately $1.96 million in overcharges.

26. Pacific did not provide a reasonable estimate of the level of improper reconnection charges. TURN estimated that improper reconnection charges were between $700,000 and $1.3 million in 1990.

27. Pacific demonstrated an indifferent disregard [*71] of its obligations to comply with its tariffs because its managers failed to exercise ordinary diligence with regard to payment processing problems.

28. The record in this proceeding does not demonstrate that the QIT will prevent future customer service abuses or tariff violations by Pacific.

29. A management audit of customer service-related operations will help deter customer service problems in the future.

30. In D.91-05-029, the Commission found that TURN demonstrated financial hardship for the calendar year 1991.

31. This decision creates a common fund from which intervenors could qualify for fees.

Conclusions of Law

1. Pacific violated D.84-06-111 when it imposed late payment charges and disconnected customers whose payments were received on time.

2. *PU Code Section 532* requires utilities to comply with tariffed offerings.

3. *PU Code Section 489* requires utilities to tariff rates and charges.

4. *PU Code Section 532* complements *PU Code Section 489* by requiring utilities to assess charges and provide services according to the provisions of their tariffs.

5. Pacific violated *PU Code Section 532* when it failed to comply with its tariffs by imposing improper [*72] late payment fees and disconnecting customers.

6. *PU Code Section 736* provides a three-year statute of limitations to claims brought under *PU Code Section 532*.

7. The statute of limitations takes effect at the point when a plaintiff discovers or should have discovered the facts essential to the cause of action.

8. Pacific should not be permitted to be unjustly enriched by mistakes for which it was responsible and where customers could not reasonably be expected to know about the mistakes.

9. The statute of limitations as applied to this case permits customers up to three years to claim improper charges and actions back to 1986.

10. *PU Code Section 734* provides that the Commission may order reparations to be paid with interest.

11. The Unclaimed Property Law requires that unclaimed utility refunds escheat to the state.

12. Pacific should be ordered to establish an account in the amount of $34.32 million, which is the adopted estimate of outstanding refunds owed to customers. The account should bear interest at a rate of 12% annually. Pacific should be ordered to withdraw future customer refunds from this account. It should be ordered to deliver one half of remaining [*73] unclaimed refunds to the Controller on February 28, 1994. The remaining balance should be delivered to the Controller three years following customer notification of erroneous charges and actions, as required by this decision.

13. Pacific should be ordered to include interest at an annual rate of 12% on future customer refunds which are the subject of this decision.

14. Pacific should be ordered to modify its tariffs to provide that it will add interest, at a rate of 1.0% per month, to any improperly assessed rates or charges.

15. Pacific should be ordered to inform customers that:

Late payment charges were improperly assessed as early as 1986 and that customers still qualify for refunds;

They may have been improperly disconnected and charged improper reconnection charges;

Improper late payment charges and disconnections may have occurred for any type of payment, including payments mailed in bar–coded envelopes provided by Pacific; and

They may qualify for a refund of returned check charges or stop–payment charges.

16. The Commission has the authority to fine utilities up to $1,000 per incident for contempt, pursuant to *PU Code Section 2113*.

17. Pacific should be ordered [*74] to reduce rates to its basic service customers by $7.5 million, plus 12% interest, which should accrue beginning the effective date of this decision. This reduction should be implemented over a one–year period in Pacific's next annual price cap filing. The amount should be applied as an exchange surcredit to the rates of all classes of customers.

18. Pacific should be ordered to deposit $7.5 million in an interest–bearing account which shall be established for the sole purpose of assisting lifeline customers with the costs of establishing telephone service.

19. CACD should be directed to oversee an audit of the management of Pacific's customer service operations, pursuant to this decision. Pacific should be ordered to pay for the audit, which should be filed in A.92–05–004.

20. TURN should be found eligible for compensation in this proceeding.

21. TURN is eligible for funding in this proceeding pursuant to Sections 1801–1813.

22. TURN is not eligible for funding from the Advocates' Trust Fund in this proceeding because other sources of funding are available.

ORDER

IT IS ORDERED that:

1. Pacific Bell (Pacific) shall, within 15 days of the effective date of this [*75] decision, establish an account in the amount of $34.32 million. The account shall accrue interest at an annual rate of 12% beginning on the effective date of this decision. Pacific shall withdraw future customer refunds from this account. It shall deliver one half of remaining unclaimed refunds, plus interest at an annual rate of 12%, to the Office of the State Controller (Controller) on February 28, 1994. The remaining balance shall be delivered to the Controller three years following customer notification of erroneous charges and actions, as required by this decision. Thirty days prior to delivering funds to the Controller's office, Pacific shall provide to the Commission Advisory and Compliance Division (CACD) an accounting of balances.

2. As part of refunds to customers which are the subject of this decision, Pacific shall include interest at an annualized rate of 12%.

3. Pacific is found in violation of Commission rules, Section 532 and Decision (D.) 84–06–111 and its tariffs.

4. Pacific is in violation of its tariffs, Section 532, and D.84–06–111.

5. Pacific shall inform current customers and those who have left Pacific's system since 1986 that:

Late payment charges [*76] were improperly assessed as early as 1986 and that customers still qualify for refunds;

They may have been improperly disconnected and charged improper reconnection charges;

Improper late payment charges and disconnections may have occurred for any type of payment, including payments mailed in bar–coded envelopes provided by Pacific; and

They may qualify for a refund of returned check charges or stop–payment charges.

Notices informing customers of these matters shall be mailed within 45 days of the effective date of this decision. Pacific shall consult with TURN and DRA before submitting the notice to the Public Advisor's Office for review and approval. Fifteen days prior to mailing, Pacific shall provide copies of draft notices to the Public Advisor's Office.

6. Pacific shall be assessed a penalty in the amount of $15 million, pursuant to Section 701.

7. Pacific shall deposit $7.5 million in an interest bearing account for the sole purpose of assisting low income customers who are qualified for lifeline with the costs of establishing telephone service.

8. Pacific shall, within 30 days of the issuance of this decision, file an advice letter proposing a method of administering

[*77] funds set aside by this order. The proposal shall be subject to Commission approval by resolution.

9. Pacific shall reduce rates to its basic service customers by $7.5 million, plus 12% interest which shall accrue beginning the effective date of this decision. This rate reduction shall be effected as a one-time z factor adjustment to Pacific's exchange surcharge in Pacific's next annual price cap filing.

10. Pacific shall, within 10 days of the issuance of this decision, modify its tariffs to provide that it shall add interest, at a rate of 12% per year, to rates and charges that are assessed in contravention of its tariffs.

11. The Executive Director shall direct CACD to oversee an audit of the management of Pacific's customer service operations pursuant to this decision. Pacific shall fund the audit, which shall be filed in Application 92-05-004.

This order is effective today.

Dated May 19, 1993, at San Francisco, California.

Table 1 (Revised)
Inappropriate Late Payment Charges
($ 000)
Interest Calculations

	Adjusted LPCs n1	Beg. Bal.	Ending Bal.	Avg. Bal.	Interest	End. Bal. Incl. Int	Already Refunded	Balance to be Refunded
1986	$4,347	$0	$4,347	$2,174	$261	$4,608		
1987	3,478	4,608	8,085	6,347	762	8,847		
1988	2,782	8,847	11,629	10,238	1,229	12,858		
1989	2,226	12,858	15,083	13,971	1,676	16,760		
1990	1,781	16,760	18,540	17,650	2,118	20,658		
1991	148	20,658	20,807	20,807	2,497	23,304		
1992		23,304	23,304	23,304	2,796	26,100	$1,960	$24,140
Totals	$14,761				$11,339			

[*78]

n1 Adjusted for 20% annual rate of decrease in inappropriate LPCs.

Inputs:

$5,080 Inappropriate LPCs ($ 000) for period 1/88 through 1/91

410 adjustment for 7 A.M. Sacto. pickup

20% annual rate of decrease in inappropriate LPCs.

3.083 yrs. covered by estimate (37 months)

12.00% interest rate

Intermediate calculations:

$5,490 LPCs adjusted for 7 A.M. Sacto. pickup

$1,781 annualized

Table 2
Inappropriate Reconnect Charges
($ 000)
Interest Calculations

	Adjusted RCs n1	Beg. Bal.	Ending Bal.	Avg. Bal.	Interest	End.Bal. Incl. Int	Already Refunded	Balance to be Refunded
1986	$1,709	$0	$1,709	$854	$103	$1,812		
1987	1,367	1,812	3,179	2,495	299	3,478		
1988	1,094	3,478	4,572	4,025	483	5,055		
1989	875	5,055	5,930	5,492	659	6,589		
1990	700	6,589	7,289	6,939	833	8,122		
1991		8,122	8,122	8,122	975	9,096		
1992		9,096	9,096	9,096	1,092	10,188	$0	$10,188
Totals	$5,745				$4,443			

n1 Adjusted for 20% annual rate of decrease in inappropriate RCs.

Inputs:

$700 Inappropriate RCs ($ 000) for 1990

20% annual rate of decrease in inappropriate RCs.

1 yr. covered by estimate

12.00% interest [*79] rate

Intermediate calculations:

$700 annualized

Toward Utility Rate Normalization, Inc., Complainant, vs. Pacific Bell (U 1001 C), Defendant

Decision No. 94–04–057, Case No. 91–03–006 (Filed March 1, 1991)

California Public Utilities Commission

1994 Cal. PUC LEXIS 313; 54 CPUC2d 122

April 20, 1994

PANEL: [*1]

Daniel Wm. Fessler, President; Patricia M. Eckert, Norman D. Shumway, P. Gregory Conlon, Jessie J. Knight, Jr., Commissioners

OPINION: ORDER ON REHEARING OF DECISION 93–05–062

In Decision (D.) 93–05–062 we found that Pacific Bell (Pacific) had violated Public Utilities (PU) Code § 532 in its processing of late payment charges. The decision requires Pacific to refund $34.32 million in overcharges and to pay a $15 million penalty. Pacific filed an application for rehearing of D.93–05–062 which alleges a number of legal and factual errors.

After considering all the allegations of error in D.93–11–026, we granted limited rehearing on the following issues: (1) the legal basis for imposing a penalty on Pacific and the disposition of the penalty; (2) the application of the statute of limitations to the refunds ordered in this case; and (3) the escheat of unclaimed refunds to the state. Because these are legal issues, we limited rehearing to additional briefing by the parties.

Concurrent opening briefs were filed by Pacific, Division of Ratepayer Advocates (DRA) and Toward Utility Rate Normalization (TURN) on December 3, 1993. Concurrent reply briefs were filed by these parties on December [*2] 23, 1993.

After carefully considering all of the pleadings on rehearing, we generally reject Pacific's allegations of error. However, we will modify the decision as set forth below. Some of the modifications we make herein address minor issues raised in Pacific's application for rehearing but not addressed by D.93–11–026.

A. The Legal Basis for the Penalty

D.93–05–062 assessed upon Pacific a penalty of $15 million, pursuant to *PU Code § 701*. n1

n1 Section 701 provides: "the commission may supervise and regulate every public utility in the State and may do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction." . . .

In its application for rehearing, Pacific argues that *PU Code § 701* does not authorize the Commission to impose a penalty because specific provisions of the *PU Code, §§ 2100 – 2119*, address how the Commission can assess penalties.

Because no party specifically addressed the applicability of § 2100 et seq., we requested additional briefs from the parties on the use of these sections for imposing a penalty in this case. Parties were asked to include [*3] an analysis of the amount of penalty that may be imposed and the disposition of the funds.

In its briefs on rehearing, Pacific contends that the Commission's only avenue for obtaining a penalty from Pacific is through an action in superior court under *PU Code § 2104* (Pacific Reply Brief, p. 1), although Pacific also concedes that the Commission has previously imposed such penalties without recourse to the superior court under the authority of § 701. (Pacific Opening Brief, p. 6.)

DRA and TURN believe that the Commission has authority under § 701 to impose penalties on Pacific, although they concede that penalties can also be recovered under § 2104.

We hold that there are two well established paths which the Commission has historically employed to impose and recover penalties.

PU Code § 701 offers one path. As we noted in D.93–05–062, there have been numerous cases in which the Commission has imposed a penalty upon a utility without bringing an action in superior court to recover such penalty. For example, in D.87–12–067 (the "marketing abuse" case) we imposed a penalty of $16.5 million upon Pacific, in order to ensure that future similar marketing abuses do not occur and to [*4] avoid unjust enrichment of Pacific. Without proceeding under *PU Code § 2104*, we ordered Pacific to charge an appropriate nonoperational expense account in the amount of $16.5 million, and to set that amount aside in a special interest bearing account, pending further disposition of the funds. Pacific complied with the order.

Similarly, in D.91–07–010 we asserted jurisdiction under *PU Code § 701* to establish minimum penalty levels for potential predatory pricing activities by Pacific or GTEC. n2

n2 Pacific argues for the first time in its opening brief on rehearing that this case is wrongly decided. However, Pacific did not seek rehearing of D.91–07–010 on this point, although it had every opportunity to do so.

We have also imposed penalties, without seeking an order from a superior court, by adjusting rates of return where the quality of service was found to be inadequate. (See Re Pacific Telephone and Telegraph *(1976) 80 CPUC 599.)* Similar to these cases, the net effect of the penalty imposed by D.93–05–062 is to reduce Pacific's authorized rate of return.

PU Code § 2104 provides an alternate path for recovery of penalties. (See, e.g., Re Southern California Water [*5] Co. *(1991) 39 CPUC2d 507, 520.)* n3

n3 Pacific cites two cases for the proposition that superior court action under § 2104 is the only means by which the Commision may impose a penalty. The first case cited by Pacific is DiMaggio v. Pacific Bell, D.92–03–031, mimeo., p. 7. To the extent that dicta in Dimaggio suggests that the Commision can only award penalties under § 2104, it is plainly wrong and we expressly disapprove of this suggestion. The second case cited by Pacific, Associated Theatres, Inc. v. Southern Pacific Ry Co., *72 CPUC 69, 71*, does not suggest that the authority granted by § 2100 et seq. is exclusive. In fact, the case actually holds that the Commission's power to punish for contempt "may be exercised in several ways, including recovering penalties brought in the name of the people . . . in a competent court of law."

The parties also differ on the amount of penalty that may be imposed. Pacific contends that the penalty per day ranges from $500 to $2,000 per day; excluding Sundays and holidays, the maximum penalty would be less than $1.8 million.

In D.93–05–062, we found that Pacific violated its late payment charge tariffs "each time it assessed [*6] improper late payment charges and reconnection fees, and disconnected customers in error." Based on the estimated number of late payment charges, Pacific violated its tariffs approximately 7.5 million times, thereby committing approximately 7.5 million offenses.

While the penalty imposed herein is approximately $2.00 per offense, rather than the minimum $500 per offense specified by *PU Code § 2107*, §§ 701 and 2104 grants the Commission the discretion to set an appropriate penalty or to compromise an action for collection of the penalty. In this case, Pacific committed approximately 7.5 million separate offenses. Thus, we could fine Pacific from $3.75 billion to 15 billion dollars. We believe we are well within our authority to set the penalty at the reduced, but still substantial, amount of $15 million.

In summary, we find that the Commission has authority under either § 701 or § 2704 to impose a penalty upon Pacific for violations of its tariffs. Following our established practice, we will allow Pacific a period of 30 days from the effective date of this decision to voluntarily pay the penalty. Thereafter, if the penalty is not paid, the General Counsel is ordered to bring [*7] and prosecute to final judgment an action to recover the $15 million penalty payment in the name of the people of the State of California in Superior Court in the County of San Francisco.

B. The Statute of Limitations

During the course of this proceeding, Pacific has taken three different positions regarding the period of time for granting refunds to customers. First, in notices to its customers, Pacific offered to refund erroneous late payment charges back to January 1, 1988. Second, earlier in this proceeding Pacific retracted its initial offer by arguing that a statute of limitations act bars recovery for erroneous late payment charges prior to March 1, 1989, two years prior to March 1, 1991, the date TURN's complaint was filed. Finally, in its brief on rehearing, Pacific abandoned its argument regarding a two-year statute of limitations and argued instead that a three-year statue of limitations began to run on March 1, 1991, and was not tolled. In effect, Pacific believes that California law bars refunds of erroneous charges incurred prior to March 1, 1988.

In D.93-05-062, we rejected Pacific's argument that a two-year statute of limitations applies to these charges. [*8] We held that late payment charges are subject to *PU Code § 532*. Therefore, *PU Code § 735* does not apply. Rather, *PU Code § 736*, which provides a three-year statute of limitations to claims under *PU Code § 532*, applies.

We also held that Pacific is mistaken in assuming that customers cannot recover improper charges assessed prior to March 1, 1989 (or pursuant to *PU Code § 736,* March 1, 1988). We ruled that:

"The statute of limitations is tolled until a plaintiff discovers or should have discovered the facts essential to the cause of action. (*CAMSI IV v. Hunter Technology Corp. (1991) 230 Cal. App. 3d 1525, 1536, Leaf v. City of San Mateo (1980) 104 Cal. App.3d 398.)*

"In this case, Pacific's customers cannot be considered to have discovered Pacific's errors until they have been notified of those errors. For customers who might have been improperly charged because they did not use Pacific's bar-coded envelopes (that is, they used white mail), the discovery date would be Pacific's publication of information about this error in February 1991. For customers who were wrongfully disconnected, or who were disconnected and charged for reconnection, or who were charged erroneous [*9] late payment charges for reasons other than having sent white mail, the statute tolls until customers have been notified of Pacific's mistake. Customers in those circumstances could not, therefore, have discovered it.

"In its reply brief, Pacific suggests that customers did, in fact, have knowledge about late payment charges, thereby precluding application of the delayed discovery rule cited by TURN. Pacific states bill notices include information about late payment charges. It argues that customers could have called Pacific to determine whether their late payment charges were indeed appropriate.

"Pacific may not rely on its customers to identify improper charges and tariff violations. While customers may have known of the policy under which charges would be applied, it defies logic to assume customers knew they were being improperly charged for several reasons. Pacific places the risk of timely post office delivery on customers. Pacific did not notify customers that it had internal billing problems, and some managers appear to have directed service representatives not to discuss known internal problems with customers who took the initiative to ask. Some service representatives [*10] may have reversed the charges of some inquiring customers. Millions of other customers, however, did not receive refunds and cannot be reasonably assumed to have known about the improper charges. Indeed, Pacific would hold its customers to a standard to which it would not hold its own officers and managers: it seeks to avoid liability in this complaint by claiming officers and managers were ignorant of payment processing problems while asking us to assume that its customers should have known about the same problems. Pacific cannot have it both ways.

"Where a utility knew or should have known that it was overcharging its customers, the benefit of the doubt must go to customers. It would be patently unfair to interpret the statute of limitations to bar customers from claiming reparations for acts of which they had no knowledge. Pacific has acknowledged that it erroneously charged customers and the evidence shows that the errors were committed as far back as 1986. We interpret the statute of limitations in this case to require customers to make a claim within three years following discovery. (Independent Consulting Services vs. Pacific Bell *(1986) 21 CPUC2d 181.)* Pacific [*11] will be ordered to refund to customers overcharges imposed as far back as 1986." (D.93-05-062, mimeo., pp. 21-23.)

In our decision granting rehearing, we requested that the parties specifically address when the cause of action accrues in this case, when the three-year statute of limitations begins to run, and when the statute is tolled.

As Pacific observes in its brief on rehearing, under a statute (such as *PU Code § 738*) which sets forth a time period in which a claim may be made, "Ordinarily, the limitations clock begins to tick when the plaintiff has suffered injury . . ." (Emphasis added.) However, Pacific also acknowledges that the clock does not "begin to tick" in certain situations. One situation where the statute does not begin to run is defined by *Jolly v. Eli Lily Co., (1988) 44 Cal.3d 1103:*

"The discovery rule provides that the accrual date of a cause of action is delayed until the plaintiff is aware of her injury and its negligent cause. A plaintiff is held to her actual knowledge as well as knowledge that could reasonably be discovered through investigation of sources open to her." (*Id. at 1109.)* (Citations omitted.)

Pacific incorrectly implies that the statute [*12] begins to run as soon as the plaintiff is injured or is actually suspicious of wrongdoing by somebody, or when a reasonable person similarly situated would have been suspicious. Rather, as stated by Jolly, the statute begins to run when a plaintiff is aware of his or her injury and its negligent cause. This awareness must be actual or based upon that which could be reasonably discovered through sources open to him or her.

As we explain in D.93–05–062, although late charges may have appeared on a customer's bill, this fact did not provide a customer with actual knowledge of any injury. A late charge was improper only if a payment was not credited on the date it was received, and the date of receipt was a fact within the exclusive knowledge of the defendant. Moreover, even if a customer who received a bill showing a late payment charge knew that "something was wrong," the customer had no basis for knowing the cause of the injury and whether such cause was negligent. Simply put, the late payment charge could have been caused by many factors, including delays in postal delivery.

Moreover, we found in D.93–05–062 that a customer's reasonable investigation of sources open to [*13] them could not enable customers to determine that they had been injured. While some customers were suspicious of being improperly charged, the record shows that the only reasonable source of information was customer service representatives and that these representatives did not inform such customers of Pacific's wrongdoing.

Indeed, given the overwhelming record that Pacific's own management was unaware that "something was wrong," that Pacific's own customer service representatives were either unaware of wrongdoing or unwilling to admit such wrongdoing to inquiring customers, we continue to be astounded by Pacific's assertions that its customers should be charged with knowing that something was wrong at Pacific.

In summary, we conclude that the cause of action accrued when consumers were improperly billed, but we also find that the cause of action was delayed (or tolled) until ratepayers became aware of their injury and its negligent cause. In this case, we find that ratepayers could not reasonably have become aware of their injury and the cause of the injury until February 1991 when Pacific itself claims to have "discovered" its improper practices and first published notice of [*14] its billing errors. Although the three–year statute of limitations began to run in February 1991, it was tolled once again in March 1991 when TURN filed this complaint. Therefore, all improper late payment charges, including those dating back to 1986, are subject to refund.

C. The Disposition of Unclaimed Refunds

In D.93–05–062, we addressed the disposition of unrecovered refunds (as distinguished from amounts which are considered penalties or fines). Consistent with our reading of the Unclaimed Property Law, we directed Pacific to deliver to the Controller unrecovered refunds soon after the statute of limitations lapses:

"The statute of limitations lapses at different times for customers who used white mail and those who did not. Although we are unable to estimate precisely different amounts for those two types of refunds, we believe it reasonable to require Pacific to deliver to the Controller half of the balance in the account in February 1994 (after which time customers who used white mail would be barred from recovering refunds). The other half shall be delivered to the Controller three years following customer notices required by this decision." (D.93–05–062, mimeo., [*15] p. 31.)

In its application for rehearing, Pacific alleged that California escheat law does not apply where the owners of the unclaimed property are not identified. Therefore, in D.93–11–026 we requested that the parties brief the application of the escheat law to this case in light of *Cory v. Public Utilities Commission (1983) 33 Cal.3d 522,* as well as Civil Code § 1519.5. In particular, we asked the parties to address the issue of when the refunds in this case would be considered "unclaimed by the owner for more than one year" under Civil Code § 1519.5.

All parties agree that Pacific should not benefit or profit from unclaimed overcharges. All parties also recognize that some customers with valid claims for a refund may not make a claim. All parties also agree that unclaimed refunds need not escheat to the State. Instead, these parties agree that the Commission has equitable powers to use these amounts for another equitable purpose.

Civil Procedure § 1519.5, which provides that certain sums will escheat to the state, further provides that nothing in this section shall be construed to change the authority of a court or administrative agency to order equitable remedies. [*16] To illustrate the power of an administrative agency to order equitable remedies, Pacific cites the case of *People ex rel. Smith v. Parkmerced Co. (1988) 198 Cal.App.3d 683, 692–93,* wherein certain fees had been collected from tenants unlawfully and were ordered refunded. When certain fees could not be refunded because former tenants could not be located, the court ordered these amounts to be paid to the Parkmerced Resident's Association.

Pacific agrees with Public Advocates that the equitable powers of the Commission under § 1519.5 are similar to the theory of "fluid recovery" often used in class action cases.

Accordingly, we will exercise our equitable powers to order that the unclaimed refunds be used to benefit those most likely to have been injured by the incorrect late payment charges. As TURN notes, an equitable use of the residue for the benefit of Pacific customers is particularly appropriate, now that the Commission may need to seek recovery under § 2104. We will follow TURN's recommendation, by amending D.93-05-062 to provide that the residue of refund amount will be distributed for the benefit of Pacific customers in a manner to be determined by the Commission [*17] after the amount of the residue, if any, is known.

We will also modify the decision to indicate a different date for the refund process to be completed, consistent with the modifications set forth above on the statute of limitations and with *Code of Civil Procedure § 1519.5*. As discussed further below, we have decided to give Pacific six months to notify customers of refunds. After that it will take some time for customers to respond, for claims to be verified, and for refunds to be mailed.

Under these circumstances, refunds cannot be considered "payable" until all customers have been notified by Pacific, about six months from the date of this order, or October 1994. Pursuant to *Code of Civil Procedure § 1519.5*, "payable" refunds can be claimed for up to a year thereafter, or October of 1995. Therefore, we will order that the remaining balance in the refund account, if any, be delivered to a separate account, bearing interest at the commercial paper rate, until disposition of this amount is determined by further Commission order.

D. Other Issues

The following discussion reviews issues raised by Pacific's application for rehearing which were not within the scope of issues [*18] to be briefed on rehearing, but which, nonetheless remain to be resolved.

Pacific first contends that the $34.32 million estimate of overcharges is seriously flawed. According to Pacific, the record does not support the estimate because reconnection charges were grossly overstated. As stated in the decision, because Pacific failed to keep records of when customer payments were actually received, the amount of overcharges can only be estimated. There is evidence that some improper reconnection fees were imposed. Pacific's analysis of reconnection charges was rejected because it indicated that there were no improper reconnection charges. Instead, we adopted the low end of the estimate proposed by TURN, which we believe to be reasonable based on the record.

Pacific also argues that there is no support for the finding that the overcharges were greater in earlier years. However, this adjustment to the 1990 estimated overcharges is based on Pacific's own testimony, which indicated that Pacific improved on its payment processing over the years in question.

The decision awards interest of 12% on the overcharges. Pacific contends that Article 15, Section 1, of the California Constitution [*19] allows interest to be no greater than 7%. However, that constitutional provision does not apply to a Commission order for reparations. A Commission order is not a "forbearance," "loan," or "judgment rendered in any court" under Article 15, Section 1. In addition, *City of North Sacramento v. Citizens Utilities Co. (1963) 218 Cal.App.2d 178*, held that Article 15, Section 1, does not apply to special proceedings before the Commission.

Pacific points out that the decision does not take into account refunds made after the evidentiary record was closed. Pacific is correct. We will therefore modify the decision to state that Pacific may file an advice letter with the Commission's Advisory and Compliance Division (CACD) that provides an accounting of such refunds. Upon approval by CACD, the amount of those refunds may be credited to the total amount of refunds set forth in the decision.

In its application for rehearing, Pacific argued that the Commission should determine the amount of overcharges after the refund program is complete because the best evidence of overcharges is the actual amount claimed. However, in its reply brief on rehearing Pacific concedes that not all valid [*20] refunds will be claimed. In Pacific's words: "We recognize that some customers with valid claims may not make them. They may have moved; they may not wish to make a claim for a small amount; there may be other reasons for failure to make a claim." (Reply Brief, p. 31.) For these reasons, in this case the best evidence of actual overcharges is the estimated amount.

Pacific objects to the notification and refund program. Pacific does not allege legal error, but states that it needs six months, rather than 45 days, to carry out the notification process. Pacific also maintains that mailing notices to former customers would not be effective. Instead, Pacific suggests advertisements as a means of contacting former customers.

The only concern that TURN and DRA have expressed with allowing more time for notices is that the decision set February 1994 as the date that the statute of limitations will have run for customers using "white mail." However, because of our modifications to the statute of limitations analysis, this date is no longer considered the date that the statute of limitations runs out. Therefore, we see no reason to refuse Pacific's request to have six months to notify [*21] customers of the refunds.

Regarding the method of notice, publication rather than direct mailing is often approved in class action cases as an effective means of notice. We believe that such notice may be even more effective than direct mailing to former customers in this case, at least for those customers who terminated service with Pacific more than one year ago. n4 Therefore, we will modify the decision to allow Pacific to use publication to notify those former customers who terminated service more than one year prior to date of this decision. Following the procedure we have required for the content of the notices, we will direct Pacific to consult with TURN and DRA before submitting a plan for publication to the Public Advisor's office for approval. The Public Advisor shall ensure that the plan, including the content of the advertisements and the scope of publication, shall be reasonably effective in notifying those customers who may have been overcharged of their rights.

n4 As TURN points out, the post office forwards mail for one year. Therefore, we believe a good portion of the customers terminating service within the past year will receive the notice by mail.

Pacific [*22] alleges that it is legal error to require Pacific to modify its tariffs to include 12% interest on overcharges without prior notice and an opportunity to be heard.

We have reconsidered this issue and have concluded that it would be more appropriate to consider such a change in a separate proceeding and that other telephone utilities should be included in such a proceeding. However, at this time we have decided to continue to determine the rate of interest on a case–by–case basis for reparations awarded under *PU Code § 734*. We will therefore delete the requirement from the decision.

In addition to the issues raised in Pacific's application for rehearing, Pacific sent a letter to the Executive Director on July 30, 1993 regarding a minor modification in the language of Ordering Paragraph 7. Because we are deleting Ordering Paragraph 7 by this order, it is not necessary to consider the requested changes.

Finally, we will make some minor modifications to the decision to correct clerical errors.

Therefore, IT IS ORDERED that D.93–05–062 is modified as set forth below:

1. The third paragraph in the section on the statute of limitations, which begins on page 21 and continues to page [*23] 22, is modified to read:

"Pacific is mistaken in assuming that customers cannot recover improper late charges assessed prior to March 1, 1989 (or pursuant to *PU Code Section 736*, March 1, 1988). A cause of action generally accrues when, under the substantive law, the wrongful act is done and the obligation or liability arises. (3 Witkin, Cal. Procedure (3rd ed. 1985) Actions, section 351, p. 380.) However, in order to ameliorate the harshness of rigid adherence to this rule, a number of exceptions have been made both by statute and judicial decision. One of the most important exceptions is the "discovery rule," which suspends the running of the statute of limitations until either the plaintiff discovers the injury and its wrongful cause, or could have discovered injury and cause, through reasonable diligence. (*Leaf v. San Mateo (1980) 104 Cal.App.3d 298, 407.)*

"In this case, Pacific's customers cannot be considered to have discovered Pacific's errors until February 1991, when the matter came to the attention of the public through a newspaper article, and subsequently through Pacific's initial outreach campaign. TURN filed its complaint in March 1991, tolling the three–year [*24] statute of limitations well before it had run."

2. In the first full paragraph on page 23, the following citation should be deleted:

"(Independent Consulting Services vs. Pacific Bell *(1986) 21 CPUC2d 181).*"

3. On page 23, the final paragraph in the section entitled "The Applicability of the Statute of Limitations" is modified to read:

"To summarize, the three–year statute of limitations began to run in February 1991. When TURN filed its complaint in March 1991, the statute of limitations was tolled. Therefore, customers may recover reparations for overcharges for the period 1986 to 1991, provided that such claims are submitted on or before October 1, 1995."

4. On page 31, the following is added at the end of the first full paragraph:

"Pacific may file an advice letter with CACD which includes an accounting of any refunds made after the close of the record in this case and before the Decision was issued. With the approval of CACD, Pacific may reduce the amount of the refunds ordered by this decision by the amount of refunds paid during that period."

5. On page 31, the final paragraph is modified to read:

"Pursuant to *Code of Civil Procedure section 1519.5*, refunds [*25] which remain "unclaimed" for more than one year after becoming "payable," escheat to the state. Because notice to customers will take about six months to complete, and the processing of refunds may take several months, the refunds cannot be considered "payable" any sooner than one year from the date of this order. Thus, the refunds will not have remained "unclaimed by the owner for more than one year after becoming payable" until October of 1995. We will require Pacific to deposit the remaining balance, if any, in the refund account as of close of business October 31, 1995, into a separate interest bearing account pending further disposition by order of the Commission.

6. On page 32, the final paragraph of the section entitled "Customer Notification" is modified to read:

"We will direct Pacific to notify current customers, as well as those customers who have terminated service with Pacific in the past year, by mail. For those persons who have not been customers of Pacific for more than one year, we believe publication is a more effective method of notice. Pacific shall consult with TURN and DRA regarding the notices which are to be mailed, as well as the content and scope [*26] of the notice by publication."

7. In the first line on page 34, the citation to In re Burns should read "*161 Cal.App.2d 137, 142 (1958).*"

8. On page 34, the last sentence is modified to read:

"Finally, we are confident that *PU Code Sections 701* and *2107* are more than adequate sources of authority to impose a fine warranted by this record."

9. On page 35, the entire section entitled "Applicability of *PU Code section 701*" is modified to read:

"Applicability of *PU Code Sections 701* and *2107*

"In numerous cases we have used *PU Code Sections 701* and *2107* to impose penalties for failure to observe our orders, decisions or tariffs. *PU Code Section 701* provides that the Commission may do "all things . . . which are necessary and convenient" in the exercise of its power and jurisdiction. *PU Code section 2107* explicitly provides that any public utility which violates the California Constitution, the PU Code, or Commission rules or decisions "is subject to a penalty of not less than five hundred dollars ($ 500) nor more than two thousand dollars ($ 2,000) for each offense." We relied on both of these sections when we recently found that Pacific would be subject to fines if it [*27] engaged in anti–competitive contract pricing. (See D.91–07–010, mimeo. at pp. 18–19.)

"We are therefore within our authority under *PU Code Sections 701* and *2107* to impose penalties on Pacific."

10. On page 36, footnote 12 is modified to read:

"Neither deterring future wrongful activity nor assuring against unjust enrichment is a prerequisite to penalties assessed under *PU Code Section 2107*. All that is required under that section is a violation of relevant statutes, rules, or decisions by a public utility."

11. On page 38, the following language is inserted as a footnote after the first sentence of the third paragraph:

"We estimate that Pacific improperly assessed approximately 7.5 million total overcharges between 1986 and early 1991. Under *PU Code Section 2107*, Pacific is subject to a penalty of at least $500, and not more than $2,000, per offense. This means that Pacific could be assessed a penalty of $3.75 billion to 15 billion dollars. We believe that under these circumstances, it is within the authority granted to the Commission under *PU Code section 701* to reduce the penalty to the more reasonable, but still substantial, amount of $15 million."

12. On [*28] page 39, the last full paragraph, and the following paragraph which begins on page 39 and ends on

page 40, are deleted and replaced by the following:

"In accordance with *PU Code section 2104*, the $15 million penalty is to be paid into the State Treasury, to the credit of the General Fund."

13. On page 47, Conclusion of Law 7 is modified to read:

"The statute of limitations under *PU Code Section 736* starts to run when a complainant discovers, or should have discovered, the facts essential to the cause of action."

14. On page 47, Conclusion of Law 9 is modified to read:

"The statute of limitations as applied to this case began to run in February of 1991, when the imposition of improper late payment charges and disconnections became public."

15. On page 47, Conclusion of Law 9a is added to read:

"The statute of limitations as applied to this case was tolled when TURN filed its complaint in March of 1991."

16. Conclusion of Law 12, starting on page 47 and continuing to page 48, is modified to read:

"Pacific should be ordered to establish an account in the amount of $34.32 million, which is the adopted estimate of outstanding refunds owed to customers, less amounts refunded [*29] after the close of the evidentiary record in this case as submitted by advice letter and approved by CACD. Pacific should be ordered to deliver the balance in the refund account as of the close of business on October 31, 1995, if any, into a separate account bearing interest at the commerical paper rate, pending further disposition of this amount by the Commission."

17. On page 48, Conclusion of Law 14 is deleted.

18. On page 48, Conclusion of Law 16 is modified to read:

"Pursuant to *PU Code Sections 701* and *2107*, the Commission has the authority to fine public utilities up to $2,000 per offense for violations of any provision of the Public Utilities Code or Commission decisions."

19. On page 48, Conclusion of Law 17 is modified to read:

"Pacific should be required to pay a penalty of $15 million. This amount should be paid into the State Treasury to the credit of the General Fund pursuant to *PU Code Section 2104*."

20. Conclusion of Law 18, starting on page 48 and continuing to page 49, is deleted.

21. On page 49, Ordering Paragraph 1, is deleted and replaced with the following:

"Pacific Bell (Pacific) shall, within 15 days of the effective date of this decision, [*30] establish an account in the amount of $34.32 million. By advice letter filing and approval of CACD, refunds paid between the close of the record in this case and the issuance of this decision shall be deducted from this account. The account shall accrue interest at an annual rate of 12% beginning on May 19, 1993. Pacific shall withdraw future customer refunds from this account."

22. On page 49, Ordering Paragraph 1a is added to read:

"The remaining balance of the unclaimed refunds on October 31, 1995, if any, shall be deposited into a separate account, bearing interest at the commercial paper rate, pending further disposition by the Commission."

23. On page 50, the first sentence of Ordering Paragraph 5 is modified to read:

"Pacific shall by direct mail inform current customers and those who have left Pacific's system in the past year that:"

24. On page 50, the last paragraph of Ordering Paragraph 5 is deleted and replaced with the following:

"Pacific shall also include such information in the notice by publication in order to inform former customers that they may qualify for refunds. Notice by mail, as well as notice by publication, shall be completed within six months [*31] of the effective date of this decision. Pacific shall consult with TURN and DRA, and shall submit the notice and publication plan to the Public Advisor's Office for review and approval at least fifteen days prior to mailing or publication."

25. On page 50, Ordering Paragraph 6 is modified to read:

"Pacific shall be assessed a penalty in the amount of $15 million, pursuant to *PU Code Sections 701* and *2107*. This amount shall be paid into the State Treasury to the credit of the General Fund. If the penalty is not paid within 30 days of the effective date of this order, the General Counsel shall bring and prosecute to final judgment an action to recover the $15 million penalty payment in the name of the people of the State of California in Superior Court in the County of San Francisco."

26. On page 50, Ordering Paragraph 7 is deleted.

27. Ordering Paragraph 8 is deleted.

28. On page 51, Ordering Paragraph 9 is deleted.

29. On page 51, Ordering Paragraph 10 is deleted.

IT IS FURTHER ORDERED that rehearing of D.93-05-062 as modified herein is denied, and the stay of D.93-05-062 is lifted. [*32]

This order is effective today.

Dated April 20, 1994, at San Francisco, California.

PG&E Nevada City Tree Trimming Violations 1997

PG&E Guilty In 1994 Sierra Blaze / 739 counts of negligence for not trimming trees

Jim Doyle, Chronicle Staff Writer

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A Nevada County jury found Pacific Gas and Electric Co. guilty yesterday of a pattern of tree-trimming violations that sparked a devastating 1994 wildfire in the Sierra.

The fire burned down a schoolhouse and 12 homes near the scenic Gold Rush town of Rough and Ready.

PG&E was convicted of 739 counts of criminal negligence for failing to trim trees near its power lines -- the biggest criminal conviction ever against the state's largest utility.

The six-man, six-woman jury delivered the verdict after three days of deliberations. It took the court clerk 1 1/2 hours to read all the counts.

PG&E, which denied all the allegations, faces up to $2 million in fines for the criminal misdemeanors. In addition, the judge could order the utility to pay restitution to property owners.

The utility will not be able to pass along to its customers any costs associated with the trial or any fines imposed as a result of the convictions, prosecutors said.

The jury deadlocked on four misdemeanor counts. Judge Carlos Baker declared a mistrial on those counts and scheduled a sentencing hearing for July 2.

The verdict comes as the utility is dogged by complaints about its fire-prevention efforts near power lines. The case may encourage similar prosecutions by other counties.

California Department of Forestry investigators have determined that several other major wildfires, and hundreds of smaller wildfires, have been caused in recent years by PG&E's failure to comply with safety regulations. PG&E has been slapped by state and county officials with several thousand tree-trimming violations.

State law sets minimum distances of up to 10 feet between flammable vegetation and high- voltage lines and also mandates firebreaks around power poles.

"Hopefully, this sends a message to upper-level PG&E management that they must do whatever is necessary to comply with the law and protect public safety," said Nevada County Deputy District Attorney Jenny Ross.

During the three-month trial, a prosecution expert testified that PG&E bilked its customers of nearly $80 million by diverting funds from its trimming program into shareholder profits.

"Of course I was disappointed by the results but not surprised," said veteran trial lawyer Joseph Russoniello, who headed PG&E's defense team. "I think the jury did as it could do with the evidence that it had, but it didn't see the whole picture."

He filed a motion yesterday asking Baker for a new trial on the grounds that evidence in the utility's favor -- for example, that its tree-trimming program met industry standards -- was wrongfully excluded.

Baker, a visiting judge from Kings County, heard the case in the Bouzy Rouge, a rose-colored tavern in the historic town of Nevada City, about 70 miles northeast of Sacramento in the Sierra foothills.

The charges stemmed from the August 1994 Trauner fire, which swept through 500 acres of thick brush and pine forests near Rough and Ready, a hamlet 10 miles west of Grass Valley. The fire reached the town limits and destroyed 12 homes and 22 other structures, including a schoolhouse built in 1868.

State forestry investigators determined that the blaze began when a 21,000-volt power line brushed against a tree limb that the utility was supposed to keep trimmed. In random spot inspections, the investigators found several hundred safety violations in western Nevada County. Nearly 200 of the violations involved "burners," where there was contact between vegetation and a power line.

At the trial, the prosecutor harped on PG&E's "chronic and widespread pattern of corporate negligence," saying that PG&E ignored the tree-clearance law to cut costs and to keep its annual profits above the $1 billion mark.

Energy industry economist Gayatri Schilberg, called by the prosecution as an expert witness, testified that PG&E diverted about $77 million from customers between 1987 and 1994 that it had told the California Public Utilities Commission was needed to protect the public from the threat of wildfires.

Perhaps the most damaging evidence came from internal documents. One internal memo by PG&E's corporate headquarters praised managers for cutting tree- trimming costs. Other memos and e-mail circulating within PG&E cited the utility's growing legal liability for fire safety. Other memos by district officers requested more funds for tree trimming.

Russoniello told the jury that PG&E's contractors had the responsibility for trimming trees along the utility's 105,000 miles of power lines in California. He said that trimmers hired under contract to handle the work had failed to perform their jobs in the early 1990s but did a good job in 1994 and 1995.

In the past two years, PG&E has spent about $150 million on tree trimming, with some 1,400 workers.

State forestry investigators blamed PG&E tree-trimming violations for causing last year's 2,100- acre wildfire in the heart of Sonoma County; the 1990 Campbell fire in Tehama County, which burned 125,000 acres and cost $10 million to fight; the 1992 Fawn Hill Fire in Placer County, which burned 250 acres and 11 homes, and the 1995 Sailor Fire in Placer County, which burned 150 acres.

Last year, the Placer County district attorney filed a criminal case against PG&E related to the Fawn Hill fire. The utility settled that case by agreeing to accept civil liability and pay $385,000 to a forest restoration conservancy.

In August 1996, PG&E came close to settling the case in Nevada County. A company vice president had agreed in writing to a plea bargain agreement in which the utility would plead guilty to multiple violations of the tree-clearance law and be sentenced to a criminal penalty of more than $100,000. But PG&E's chief executive officer, Stanley Skinner, decided to back out of the deal and face trial.

In 1995, PG&E pleaded no contest in Nevada County to three misdemeanor counts of failing to keep its power lines free of vegetation and paid $2,400 in fines. In 1990, PG&E pleaded no contest in Sonoma County to 10 similar counts and was fined $10,000.

Order Instituting Rulemaking for Electric Distribution Facility Standard Setting. (U 39 E)
Decision 98-03-036, Rulemaking No.96-11-004 (Filed November 6, 1996)

California Public Utilities Commission
1998 Cal. PUC LEXIS 71; 78 CPUC2d 706
March 12, 1998

9 of 15 DOCUMENTS

Order Instituting Rulemaking for Electric Distribution Facility Standard Setting. (U 39 E)

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California Public Utilities Commission

1998 Cal. PUC LEXIS 71; 78 CPUC2d 706

March 12, 1998

PANEL: [*1]

Richard A. Bilas, President; P. Gregory Conlon, Jessie J. Knight, Jr., Henry M. Duque, Josiah L. Neeper, Commissioners

OPINION: OPINION

Summary

This decision proposes rules to govern the electric utilities' planning for and response to emergencies and major power outages. The rules are proposed pursuant to *Public Utilities Code Section 364(b)* and as part of the Commission's ongoing efforts to develop and refine standards to promote the safety and reliability of the state's electric utility distribution system. We also propose minor modifications to accident reporting requirements by electric utilities.

I. Background

Section 364(b) states in part:

> "The Commission shall . . . adopt standards for operation, reliability, and safety during periods of emergency and disaster. The Commission shall require each utility to report annually on its compliance with the standards. That report shall be made available to the public.

Decision (D.) 97-03-070 directed the utilities to propose such standards no later than August 1, 1997. Subsequently, the date was moved to October 1, 1997 in order to provide the utilities an opportunity to coordinate their efforts with the state's Independent **[*2]** System Operator (ISO).

Prior to the filing of utility proposals, the California Utilities Emergency Association (CUEA) formed a committee of utilities to develop a single proposal for emergency standards. n1 As a result of the efforts of the CUEA committee, several parties filed a "Joint Party Proposal" (Joint Proposal) on October 1, 1997. Those parties are Pacific Gas and Electric Company (PG&E), PacifiCorp, San Diego Gas & Electric Company (SDG&E), Sierra Pacific Power Company, Southern California Edison Company, Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District, CUEA, and the International Brotherhood of Electrical Workers Local 1245 (IBEW). On the same day, The Utility Reform Network (TURN) filed a proposal which seeks to supplement the Joint Proposal.

n1 CUEA is a voluntary association whose members are energy, water and telecommunications utilities, utility districts and local governments who provide utility services.

The proponents of the Joint Proposal, Office of Ratepayer **[*3]** Advocates (ORA), TURN, and IBEW subsequently filed comments on the Joint Proposal or the TURN proposal or both.

On a related issue, the Commission solicited comments from parties in D.97-03-070 as to whether Commission rules regarding electric distribution system safety and reliability should apply to municipal and publicly-owned utilities. On September 15, 1997, several parties filed comments on this subject.

II. Emergency Rules Proposed by the Parties

A. Joint Proposal

In general, the Joint Proposal requires the utilities to prepare an emergency response plan, enter into mutual assistance agreements with other utilities, provide annual training to employees, adhere to certain communications and coordination requirements during an emergency or outage, and file an annual report.

No party objects to the majority of the Joint Proposal. Parties have some suggestions with regard to certain of its elements.

TURN raises concerns that the Joint Proposal provides too many opportunities for the utilities to claim extenuating circumstances if they do not meet the standards set forth in the rules. TURN proposes strengthening the standards in the Joint Proposal with regard to utility **[*4]** liability for restoring service and meeting quantitative goals.

ORA generally supports the Joint Proposal, commenting that the utilities and their customers will benefit from a coordinated response plan. ORA makes several minor suggestions mainly in support of TURN's modifications.

The Director of the Governor's Office of Emergency Services (OES) sent a letter to the assigned administrative law judge (ALJ) expressing general support for the Joint Proposal but recommending that it include more timely activation of notification and evaluation procedures. n2

n2 The letter is not technically part of the formal record but is included in the formal file of the proceeding.

The ISO also sent a letter to the ALJ stating its intent to develop emergency standards that are complementary to those adopted for the distribution companies. n3

n3 The letter is not technically part of the formal record but is included in the formal file of the proceeding.

[*5]

The IBEW generally supports the Joint Proposal but objects to the Joint Proposal's statement to the effect that no correlation exists between the number of personnel and restoration times. IBEW believe the converse is "beyond dispute."

B. TURN's Proposal

TURN's proposal is generally the same as the Joint Proposal modified to address certain concerns. TURN's proposal requires that the utilities maintain 95% of the number of employees of maintenance crews that were available at the time of the utilities' performance-based ratemaking (PBR) or general rate case filings; train call center representatives for emergency activities; not fall below a certain level of busy signals at the call centers during emergencies; and assure that any computerized outage management system is operational 99.5% of the time during an emergency.

Parties to the Joint Proposal object to the provisions in TURN's proposal that create mandatory staffing requirements and that require call center training, commenting that both would reduce the utilities' flexibility to manage the system during emergencies. They also object to TURN's proposed standard for maintaining less than 50% busy signals in the call centers **[*6]** during emergencies, commenting that such a standard does not address the quality of information to customers and relies on the reliability of telecommunications systems over which the electric utilities have no control.

C. Discussion

The need for standards governing the utilities' responses to emergencies and major outages has become increasingly more obvious in recent years. Our review of PG&E's response to storm damage in 1995 and 1996 underscored the problems associated with a lack of benchmarks by which to judge utility performance and the reliability of electric service. Since then, the California Legislature codified the requirement to have emergency standards in place as part of a larger Legislative initiative to promote competition in electric markets. As we have stated, and as Assembly Bill (AB) 1890 implies, competition in electric markets may impose pressures on distribution utilities to compromise system safety and reliability in order to be competitive in generation markets. The standards we have adopted in past decisions, and those we propose today, recognize the need for increased regulatory oversight of the monopolistic distribution system in order to assure the **[*7]** continued safety and reliability of that system.

We appreciate the efforts of the parties to present comprehensive proposals here. Although we do not describe here every element of the proposals or the comments on them, we propose standards following substantial review of the record by the Commission and its staff. We believe the rules we propose today are (1) broad enough to recognize the need for management discretion so that each utility may tailor its emergency response and planning programs according to the nature of its resources, expertise, and service area; (2) specific enough to permit the Commission to judge utility performance before, during and after emergencies and major outages; (3) attentive to the needs of customers and the public generally with regard to information and reliable service. The proposed rules also recognize the need for regulation to provide measurable incentives for utilities to plan for and respond competently to emergencies and major outages. In that regard, we propose specific penalties for the failure of a utility to restore power in specified timeframes. In addition to providing a financial incentive for utility performance and planning, the penalty **[*8]** may recognize, however crudely, the value of power to customers generally, especially following an extended outage.

In the broadest sense, the rules we propose today require the jurisdictional electric utilities to:

1. Create an emergency plan, follow it, and update it annually;

2. Train staff to handle emergencies and outages;

3. Coordinate with media and interested governmental agencies in disseminating information to the public about emergencies and major outages;

4. Develop mutual assistance agreements with other utilities and take advantage of them when appropriate;

5. Conduct annual emergency exercises in cooperation with interested agencies.

None of the activities included in the standards we propose today differ substantially from the types of efforts the utilities already undertake in preparation for emergencies or in response to them. The proposed standards may differ from existing utility programs somewhat in their scope or the way the utilities are required to involve third parties. In general, however, they are the standards the utilities themselves have proposed with a few exceptions. For example, we have removed language which arguably excuses the utilities **[*9]** from compliance with the standards or protects them from Commission action. The Commission may determine in specific instances that the utility acted reasonably even if it was unable to comply with the rules, consistent with past practice. We also remove references to the application of the standards to entities which are outside our jurisdiction. While others may find the standards useful, we do not need to provide permission for others to adopt them. We also remove language which asserts facts which may be subject to dispute, such as that referring to a lack of correlation between the number of utility employees and restoration times. A general order is an inappropriate document for making factual findings that are the subject of controversy, especially where, as here, we have not explored the allegations in hearings. Finally, we do not adopt TURN's proposals that the utilities maintain certain crew levels and assure computer systems are operational for specified periods, consistent with our view that the utilities should be responsible for and have discretion to meet the standards in whatever way they believe is most effective and efficient.

III. Applicability of Commission [*10] Safety and Reliability Rules to Municipal and Publicly-Owned Electric Utilities

D.97-03-070 adopted minimum inspection cycles applicable to overhead, padmounted, and underground equipment of electric distribution systems. In that order, the Commission solicited the comments of parties regarding whether the Commission should apply reliability and safety standards to utilities that are not within its ratemaking jurisdiction, that is, those that are publicly-owned (herein referred to as "publicly-owned utilities," and including municipal utilities, public utilities districts, and other electric utilities that are operated by governmental or quasi-governmental agencies). Numerous parties responded to this invitation, namely, California Municipal Utilities Association (CMUA), n4 Merced Irrigation District (MID), LADWP, California Utility Employees (CUE), ORA, PG&E, and TURN.

n4 CMUA represents LADWP, Sacramento Municipal Utility District and numerous other publicly-owned utilities.

CMUA states that its members provide **[*11]** high-quality, safe electric service and do not need the Commission's regulatory oversight to continue this effort. It expresses concern that the Commission's standards would be duplicative of efforts already undertaken by the publicly-owned utilities to assure public safety. CMUA argues that Section 364(a) restricts the Commission's authority to regulate publicly-owned utilities with regard to public safety matters. It adds that its members intend to continue to work cooperatively with their investor-owned counterparts to help prevent and respond to emergencies and system outages. MID makes similar comments, adding that the Commission does not have the authority to impose costs on publicly-owned utilities. LADWP also makes similar comments and observes that the Commission's initiative here resulted from conditions affecting investor-owned utilities, not publicly-owned utilities.

CUE argues that the Commission has the authority to require publicly-owned utilities to comply with Commission rules governing construction and maintenance and that it should require them to comply with those rules. CUE believes that Section 364(a) did not intend to change the Commission's historic role in **[*12]** regulating the safety of publicly-owned utilities' systems but rather simply set a deadline by which the Commission was to implement certain standards for investor-owned utilities.

TURN believes the Commission should apply safety standards to publicly-owned utilities in part due to the interdependence of utility systems which makes investor-owned utility facilities vulnerable when those of a publicly-owned utilities create damage or hazard. TURN suggests that publicly-owned utilities' compliance with Commission standards need not be burdensome if their local regulatory authorities are responsible for monitoring compliance.

ORA believes public safety is best served if all utilities are subject to the same standards and operational protocols during emergencies.

PG&E also argues that the Commission should adopt uniform standards for all public utilities notwithstanding their ownership. It argues that the Commission has had longstanding jurisdiction over the safety of publicly-owned utilities' operations. PG&E believes that permitting publicly-owned utilities to adopt independent safety and reliability standards would, by definition, lead to unacceptable levels of maintenance and inconsistency **[*13]** in administering interconnected systems. PG&E also believes that fairness requires that publicly-owned utilities be subject to the same standards as investor-owned utilities.

Discussion. The Commission has historically had authority over the public safety aspects of publicly-owned utilities. *Public Utilities Code, Sections 8001-8057* confer on the Commission the authority to regulate the state's electric systems "for the purpose of safety to employees and the general public." The law provides that this Commission not only has the authority to regulate public safety aspects of the publicly-owned utilities' operations, but that it has a duty to do so: Sections 8037 and 8056 require the Commission to enforce these provisions. The Commission's authority over such regulation has been confirmed by the court, which has found that the Commission has jurisdiction over publicly-owned utilities' maintenance and construction of electric systems (*Polk v. City of Los Angeles (1945) 26 Cal.2d 519, 540).*

The Legislature did not change the Commission's jurisdiction over publicly-owned utilities when it enacted Section 364(a). That section merely directs the Commission to implement standards for **[*14]** emergency operations by a certain date and directed that they apply to investor-owned utilities. We agree that neither the statutes nor the courts require that these particular standards are applicable to publicly-owned utilities. The statute nevertheless does not change the role of the Commission in regulating publicly-owned utilities with regard to maintenance and construction of the electric system and leaves in place Sections 8001-8057.

Having determined that the Commission has jurisdiction over maintenance and construction of publicly-owned utilities' electric systems, we consider whether we should apply the same standards to all utilities in the state. We are not convinced that the regulations we would apply to the publicly-owned utilities would be duplicative. Some may be more stringent and some may be less stringent than those the publicly-owned utilities have designed for themselves. Those that are less stringent impose no burden or duplication on the utility. Those that are more stringent are not duplicative. The standards we adopted in D.97-03-070 are based on industry standards and designed to protect the public. To the extent we require inspections that are more frequent **[*15]** than those conducted by a publicly-owned utility today, the requirement is reasonable and imposed on behalf of the public's safety.

As some commenters observe, we initiated this inquiry as the result of circumstances involving a single investor-owned utility. Nevertheless, the logic behind our decision to implement new rules applies to publicly-owned utilities as well as investor-owned utilities, specifically, that the initiation of competition in generation markets imposes cost-cutting pressures on electric utilities which may motivate them to compromise the safety and reliability of their distribution systems. The circumstance applies even if the publicly-owned utility does not permit or pursue competitive generation markets in its own territory. The fact that competition exists on its periphery will create competitive pressures for the publicly-owned utility and affect its management.

It is not the Commission's intent to impose undue burdens on any utility but rather to find the most effective and efficient methods of protecting the public. In that context, we find that flexibility is warranted in certain cases. For example, a publicly-owned utility may be accomplishing the objectives **[*16]** of a rule in ways which are reasonable but different from the specific rule. We also recognize that some publicly-owned utilities are very small and unable to accommodate some of the reporting requirements we might impose.

We intend to apply the rules we adopted in D.97-03-070 to all of the state's utilities, including publicly-owned utilities. We will, however, consider appeals from a publicly-owned utility for exemptions from specified rules upon a showing that the utility's local regulatory authority is actively overseeing the matters at issue. For instance, if the publicly-owned utility's local regulatory authority has adopted specific inspection standards that have been implemented by the publicly-owned utility and that are reasonable given industry standards, we will defer to the local authority. Similarly, we will consider exemptions from annual reporting requirements if the publicly-owned utility can demonstrate that its local regulatory authority is actively monitoring the utility's compliance with related public safety rules and programs. We will permit the publicly-owned utility to seek such exemptions by way of advice letter and subject to Commission resolution.

IV. [*17] Accident Reporting

In light of experience with accident reporting and recent fires which have allegedly resulted from overgrown vegetation around utility power lines, the Commission proposes to modify to some extent the rules adopted in D.96-09-045. The proposed rules are attached as Appendix B. In general, they require the utilities to provide written reports on accidents in a more timely fashion, to improve the content of those reports, and to submit reports following accidents involving vegetation foliage around utility power lines.

V. Procedures for Development of Final Rules

The Commission herein proposes the rules attached as Appendix A and Appendix B. Parties may comment on the rules with 20 days of the effective date of this order. The Commission intends to issue final rules as soon as possible thereafter.

Findings of Fact

1. The Commission initiated this inquiry in recognition that competition in generation markets may put pressure on electric utilities to compromise distribution system maintenance and reliability and pursuant to Section 364(b).

2. The prospects for competition affect publicly-owned utilities as well as investor-owned utilities.

3. The Commission's **[*18]** objective to promote public safety on the electric systems of publicly-owned utilities may be fulfilled where local regulatory authorities actively oversee the publicly-owned utility's safety programs, where such programs are consistent with industry standards or otherwise reasonable.

4. Section 364(b) requires the Commission to adopt certain standards by a certain date which would govern investor-owned utilities. The statute is silent with regard to publicly-owned utilities.

Conclusions of Law

1. Sections 8001-8057 confer jurisdiction on the Commission over the safety of the electric systems of all types of utilities in the state.

2. The Legislature did not change the Commission's jurisdiction over the public safety aspects of the electric systems of publicly-owned utilities when it enacted AB 1890.

3. The Commission should propose to adopt the rules attached as Appendix A and Appendix B and provide an opportunity for interested parties to comment on them.

4. The Commission should require the state's publicly-owned utilities to comply with the standards adopted in D.97-03-070 or to seek exemptions from specified standards by way of advice letter.

ORDER

IT IS ORDERED [*19] that:

1. The Commission proposes to adopt the rules and standards attached as Appendix A and Appendix B.

2. Parties who wish to comment on the rules proposed in Appendix A and Appendix B shall file such comments no later than 20 days from the effective date of this order. Responsive comments shall be filed no later than 27 days from the effective date of this order.

3. The state's publicly-owned utilities shall comply with the inspection and maintenance standards adopted in Decision (D.) 97-03-070. Each of the state's publicly-owned utilities shall submit a letter to the Commission's Energy Division within 30 days of the effective date of this order. The letter shall inform the Commission of the publicly-owned utility's intent to implement the Commission's standards or to seek exemptions from certain standards, which the letter shall specify. A publicly-owned utility may seek an exemption from specific standards by way of advice letter which demonstrates that its local regulatory authority actively oversees the relevant utility maintenance and inspection activities and that the publicly-owned utility's related inspection and maintenance program is reasonable in consideration of prevailing **[*20]** industry practices and standards. A publicly-owned utility that fails to implement the standards or seek exemptions from specified standards within 60 days of the effective date of this order shall be in violation of this order.

This order is effective today.

Dated March 12, 1998, at San Francisco, California.

I will file a concurring opinion.

/s/ JESSIE J. KNIGHT, JR. Commissioner

I will file a concurring opinion.

/s/ P. GREGORY CONLON Commissioner

APPENDIX A

Proposed General Order No. ___

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Standards for Operation, Reliability, and Safety During Emergencies and Disasters

Applicability: This General Order applies to all electric utilities subject to the jurisdiction of the CPUC with regard to matters relating to electric service reliability and/or safety.

Purpose: The purpose of these standards is to insure that jurisdictional electric utilities are prepared for emergencies and disasters in order to minimize damage and inconvenience to the public which may occur as a result of electric system failures, major outages, or hazards posed by damage to electric distribution facilities. The standards **[*21]** will facilitate the Commission's investigations into the reasonableness of the utility's response to emergencies and major outages. Such investigations will be conducted following every major outage, pursuant to and consistent with *Public Utilities Code Section 364(c)* and Commission policy.

Summary: The following rules require each jurisdictional electric utility to:

* Prepare an emergency response plan and update the plan annually. Standard 1.

* Enter into mutual assistance agreements with other utilities. Standard 2.

* Conduct annual emergency training and exercises using the utilities emergency response plan. Standard 3.

* Develop a strategy for informing the public and relevant agencies of a major outage. Standard 4.

* Coordinate internal activities during a major outage in a timely manner. Standard 5.

* Notify relevant individuals and agencies of an emergency or major outage in a timely manner. Standard 6.

* Evaluate the need for mutual assistance during a major outage. Standard 7.

* Inform the public and relevant public safety agencies of the estimated time for restoring power during a major outage. Standard 8.

* Train additional personnel to assist with **[*22]** emergency activities. Standard 9.

* Coordinate emergency plans with state and local public safety agencies. Standard 10.

* File an annual report describing compliance with these standards. Standard 11.

Definitions

Accessible: A condition which permits safe and legal access.

Appropriate Regulatory Authority: The agency or governmental body responsible for regulation or governance of the utility.

Critical Customers: Customers requiring electric service for life sustaining equipment.

Emergency or Disaster: An event which, in the context of this general order, results in a major outage, hazards or damage on the electric system. Emergencies and disasters include natural events (including but not limited to storms, lightning strikes, fires, floods, hurricanes, volcanic activity, landslides, earthquakes, windstorms, tidal waves and the Governor's early warning of an earthquake or volcanic eruption) and events not caused by nature (including but not limited to terrorist activities, riots, labor strikes, civil disobedience, wars, chemical spills, explosions, deterioration of facilities, faulty maintenance or use of the system, and airplane or train collisions.)
[*23]
Essential Customers: Customers requiring electric service to provide essential public health and safety services.

Major Outage: Consistent with *Public Utilities Code Section 364*, a major outage occurs when 10 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service. For utilities with less than 150,000 customers within California, a major outage occurs when 50 percent of the electric utility's serviceable customers experience a simultaneous, non-momentary interruption of service.

Safety Standby: Interim activities undertaken to mitigate immediate public safety hazards.

Serviceable: Accessible, prepared, and properly equipped to receive service.

Standard 1. Emergency Response Plan

The utility shall prepare an emergency response plan ("plan") setting forth anticipated responses to emergencies and major outages. The plan will help assure the utility is best able to protect life and property during an emergency or major outage and communicate the scope and expected duration of an outage. The plan shall include the following elements:

A. Internal Coordination

The plan shall describe **[*24]** the utility's procedures for coordinating internal activities during an emergency or major outage, including how the utility will gather, process, and disseminate information within the service area, and coordinate activities to restore service. The plan shall describe how the utility will determine priorities and allocate internal resources for restoring service. The plan shall describe how and where managers will coordinate internal activities depending on the nature of the emergency or outage.

B. ISO/TO Coordination

The plan shall describe how the utility will coordinate its efforts with the ISO, including how it will gather, process and disseminate information from the ISO, and how the utility will establish priorities and estimates of service restoration. A utility that does not deal directly with the ISO shall describe how it will coordinate its efforts with the TO.

C. Media Coordination

The plan shall describe how the utility will make timely and complete information available to the media before, during and immediately after a major outage. Such information shall include estimated restoration times and a description of potential safety hazards if they exist.

[*25]

D. External and Government Coordination

The plan shall describe how the utility will coordinate emergency activities with appropriate state and local government agencies. The utility shall maintain lists of contacts at each agency which shall be included in the plan and readily accessible to employees responsible for coordinating emergency communications. The utilities shall adhere to the principles of California's Standardized Emergency Management System (SEMS) to the extent possible during emergency situations and, during major outages, use the Response Information Management (RIMS) in their communications with local, county and state authorities. The utility's emergency center shall be prepared to operate a RIMS terminal no later than October 1, 1998.

E. Safety Considerations

The plan shall describe how the utility will assure the safety of the public and utility employees and the utility's procedures for safety standby. The plan shall describe how the utility will reallocate resources to respond to an increased number of reports concerning unsafe conditions.

F. Damage Assessment

The plan shall describe the process for assessing damage to the utility system **[*26]** and the property of others where the utility system may have caused such damage. The plan shall describe how the utility will reallocate resources to respond expeditiously to safety hazards and system damage. The plan shall describe how the utility will set priorities, facilitate communication, and restore service. During a major outage or emergency, the utility shall provide an assessment of damage and resource needs to the Utilities Branch of the Office of Emergency Services or its successor.

G. Customer Communication

The plan shall describe procedures for informing customers of conditions before, during and immediately following a major outage. The plan shall describe how the utility will inform customers of the estimated time when service will be restored in each affected geographic area. The utility shall provide to customers and public safety agencies updated estimates of service restoration as information becomes available.

H. Restoration Priority Guidelines

The plan shall include guidelines for setting priorities for service restoration. In general, the utility shall set priorities so that service is restored first to critical and essential customers, and so **[*27]** that the largest number of customers receive service in the shortest amount of time.

I. Mutual Assistance

The plan shall describe how the utility intends to employ resources available pursuant to mutual assistance agreements for emergency response. Mutual assistance shall be requested when local resources are inadequate to assure timely restoration of service or public safety. Mutual assistance need not be requested if it would not substantially improve restoration times or mitigate safety hazards.

J. Plan Update

The plan shall be updated annually to incorporate changes in procedures, conditions, law or Commission policy. The utility shall submit plan updates as part of the annual report required by Standard 11.

Standard 2. Mutual Assistance Agreement(s)

The utility shall enter into mutual assistance agreement(s), such as those facilitated by the California Utilities Emergency Association, with bordering electric utilities and each of the three largest electric utilities serving the state which are subject to Commission jurisdiction. The agreements shall be submitted annually to CPUC designated staff as part of the report required by Standard 11. **[*28]** The agreements shall include the following elements:

A. Resources that are available to be shared.

B. Procedures for requesting and providing assistance.

C. Provisions for payment, cost recovery, liability and other financial arrangements.

D. Activation and deactivation criteria.

Standard 3. Emergency Training and Exercises

A. The utility shall conduct an exercise annually using the procedures set forth in the utility's emergency plan. If the utility uses the plan during the twelve-month period in responding to an emergency or major outage, the utility is not required to conduct an exercise for that period.

B. The utility shall annually evaluate its response to an exercise, emergency or major outage. The evaluation shall be provided to the CPUC as part of the report required by Standard 11.

C. The utility shall annually train designated personnel in preparation for emergencies and major outages. The training shall be designed to overcome problems identified in the evaluations of responses to an emergency, major outage or exercise and shall reflect relevant changes to the plan.

D. The utility shall provide no less than ten days notice of its annual exercise **[*29]** to appropriate state and local authorities, including the CPUC, state and regional offices of the OES or its successor, the California Energy Commission, and emergency offices of the counties in which the exercise is to be performed. The utility shall participate in other emergency exercises designed to address problems on electric distribution facilities or services, including those emergency exercises of the state and regional offices of the OES or its successor, and county emergency offices.

Standard 4. Communications Strategy

The utility shall develop and maintain a written strategy for how it will communicate with the public before, during and immediately following major outages and emergencies as follows:

A. Customer Communications - Media & Call Center

The communications strategy shall describe how the utility will provide information to customers by way of its call center and other communications media before, during and immediately following an emergency or major outage. The strategy shall anticipate the use of radio, television, newspapers, mail and electronic communications media.

B. Government

The communications strategy shall describe how **[*30]** the utility will coordinate its communications with appropriate state and local government agencies, including the CPUC, OES, CEC and emergency offices of counties in which the utility offers services. The utility shall negotiate agreements with appropriate authorities to 1) allow the utility to clear roads when the utility has the equipment, expertise, and resources to do so; 2) allow the utility to inspect its facilities where appropriate; 3) identify individuals who should be contacted in government agencies and within the utility in the case of an outage or emergency; 4) coordinate the response plan with those of relevant state and local agencies; 5) coordinate with OES or its successor regarding the use of SEMS and RIMS in the utility's emergency response communications systems at the utility's corporate and district offices.

C. Independent System Operator/Transmission Owner

The communications strategy will describe how the utility will coordinate its communications with the ISO and/or the TO. The utility shall cooperate with the ISO/TO to coordinate the information provided to customers, media, and governmental agencies when the operation of the transmission system affects **[*31]** customer service.

D. Call Center Standards

The utility shall adhere to the following standards applicable to its call center during or in anticipation of emergency situations:

a. Achieve an average queue wait of less than 40 seconds, and busy signal occurrence of less than 3% during outages.

b. Explore mutual assistance opportunities with other utilities and assure backup assistance from vendors.

c. Provide backup call center employees with adequate orientation to utility's service area and customers. All call center employees, including regular, backup and emergency must be familiar with city names and locations, local landmarks, and streets in affected areas.

d. Develop a phone system that would either 1) allow the customer to choose an alternative from a menu that would provide their service areas restoration schedule, or 2) allow the customer to leave a message with their specific concerns and outage information, that would call them back with either a personal (live) or recorded estimate of restoration time for their service area.

i. The return call would be made within one hour of leaving message.

ii. If a restoration estimate is not available within one **[*32]** hour, (1) a call to the customer letting them know the message was received and information will be provided as available will be made and (2) when restoration information is available; another call will be made to the customer informing them of the estimate.

e. Train customer service representatives to enable them to understand and identify potential service and safety problems.

Standard 5. Activation Standard

Within one hour of a major outage, the utility shall begin coordinating its internal resources as set forth in its emergency plan.

Standard 6. Initial Notification Standard

Within one hour of a major outage, the utility shall notify the Warning Center at the Office of Emergency Services and the CPUC of the location, possible cause and expected duration of the outage. The Warning Center at the OES is expected to notify other state and local agencies of the outage. Subsequent contacts between state and local agencies and the utility shall be conducted between personnel identified in advance, as set forth in Standard 4.B.

Standard 7. Mutual Assistance Evaluation Standard

No later than 4 hours after the onset of a major outage, **[*33]** the utility shall evaluate and document the need for mutual assistance. The utility is not required to seek assistance if it would not substantially expedite restoration of electric service or promote public safety. The utility should reevaluate the need for assistance throughout the period of the outage.

Standard 8. Major Outage and Restoration Estimate Communication Standard

A. Within 2 hours of a major outage, the utility shall make information available to customers through its call center and notify the media of the major outage, its location, expected duration and cause. The utility shall provide estimates of restoration times as soon as possible following an initial assessment of damage and the establishment of priorities for service restoration.

B. Within 4 hours of the initial damage assessment and the establishment of priorities for restoring service, the utility shall make available through its call center and to the media the estimated service restoration times by geographic area. If the utility is unable to estimate a restoration time for a certain area, the utility shall so state.

C. Using RIMS and other methods of communication, the utility shall **[*34]** inform the OES Utilities Branch of significant changes in the status of the event or damage or restoration times as the change occur to the extent possible and otherwise at intervals not to exceed four hours.

Standard 9. Personnel Redeployment Planning Standard

The utility shall maintain a training and redeployment plan for performing safety standby activities and assessing damage during a major outage or emergency. The utility should plan to have personnel available to augment the number of employees whose duties include safety standby and damage assessment activities. The utility shall identify and train additional employees to perform safety standby activities and assess damage during emergencies and major outages and in lieu of their normal duties.

Standard 10. Annual Pre-Event Coordination Standard

The utility shall annually coordinate emergency preparations with state and regional offices of the OES or its successor, the CPUC, the CEC, county and local government agencies in the utility's territory, other utilities and the ISO/TO. As part of such activities, the utility shall establish and confirm contacts and communication channels, plan the **[*35]** exchange of emergency planning and response information, and participate in emergency exercises or training. This coordination shall be consistent with the principles of SEMS and use the RIMS communication system. The utility shall coordinate its activities with local and regional offices of the utility and relevant state and local agencies.

Standard 11. Annual Report

The utility shall annually report to the CPUC by October 31 regarding its compliance with this general order for the previous twelve months ending June 30. The annual report shall identify and describe any modifications to the utility's emergency plan.

Standard 12. Restoration Criteria

The utility shall maintain sufficient resources to restore power within 24 hours to 90% of customers who lost service; within 48 hours to 5% of customers who lost power; and within 72 hours the remaining 5% of customers who lost power. Within 30 days of an emergency or major outage, the utility shall provide to CPUC designated staff data which permits an analysis of whether the utility met these restoration requirements.

Penalties

The Commission may penalize the utility for non-compliance with **[*36]** any of the standards set forth in this general order and consistent with the Public Utilities Code. Failure to comply with the restoration requirements set forth in Standard 12 creates a prima facie case of a violation of this general order. In such cases, the Commission will impose penalties unless the utility is able to demonstrate affirmatively that (1) it could not have fulfilled the requirements of Standard 12 with additional personnel or improved system maintenance and; (2) that it has complied with all orders, rules and law setting forth standards for maintenance and repair of relevant facilities. The minimum penalty for failure to comply with Standard 12 shall be equal to the number of customer-hours which exceed the standards set forth in Standard 12 multiplied by $ 10.

(END OF APPENDIX A)

APPENDIX B

ACCIDENT REPORTING REQUIREMENTS

1. Within 2 hours of a reportable incident, the utility shall provide notice to designated CPUC staff of the general nature of the incident, its cause and estimated damage. The notice shall identify the time and date of the incident, the time and date of notice to the Commission, the location of the incident, casualties which resulted **[*37]** from the incident, identification of casualties and property damage, and the name and telephone number of a utility contact person. This notice may be by telephone, fax, or electronic mail during business hours. During other times, the notice shall be by fax or electronic mail.

2. Within twenty business days of a reportable incident, the utility shall provide to designated CPUC staff a written account of the incident which includes a detailed description of the nature of the incident, its cause and estimated damage. The report shall identify the time and date of the incident, the time and date of the notice to the Commission, the location of the incident, casualties which resulted from the incident, identification of casualties and property damage. The report shall include a description of the utility's response to the incident and the measures the utility took to repair facilities and/or remedy any related problems on the system which may have contributed to the incident.

3. Reportable incidents are those which: (a) result in fatality or personal injury rising to the level of in-patient hospitalization and attributable or allegedly attributable to utility owned facilities; (b) **[*38]** are the subject of significant public attention or media coverage and are attributable or allegedly attributable to utility facilities; (c) involve or allegedly involve trees or other vegetation in the vicinity of power lines and result in fire and/or personal injury whether or not in-patient hospitalization is required.

4. Incidents involving damage to property of the utility or others estimated to exceed $ 20,000 that are attributable or allegedly attributable to utility owned facilities shall be reported within 60 days of their occurrence to designated staff of the CPUC. The report shall be structured in a form acceptable to the designated staff.

(END OF APPENDIX B)

Commissioner Jessie J. Knight, Jr., Concurring:

It is true that California needs standards for governing the responses of the monopoly utilities to emergencies and major power outages. The Commission is required to have emergency standards in place, as part of the state's restructuring of the electric industry.

However, I disagree with at least one conclusion in the proposed order. The dicta of the proposed order indicates that competition in electric markets may impose pressures on distribution utilities to **[*39]** compromise system safety and reliability in order to accommodate competitive generation markets. While this is a hypothetical possibility, it may also prove to be untrue for California's future. In California, a new breed of companies and enterprises are emerging due to its burgeoning restructuring efforts. The business of the utility distribution company (UDC) is focused now more than ever on the distribution of electricity, rather than issues around its generation. It is my belief that this new focus will more likely enhance system safety and reliability as time rolls on. When the UDC's business is solely distribution, the economic incentive is to provide service, safety and reliability.

While I whole-heartedly empathize with the goals of this proposed order, I am concerned by the direction and tone articulated therein, thus fuelling my skepticism of some of the rules which are proposed. I am not convinced that there has been an adequate determination of the relative benefits and costs of the standards which the decision places before us. In order to assess these rules fairly, we must determine such benefits and costs before we impose them on the utilities.

There are a few issues **[*40]** that I would like to have interested parties explore in their comments. First, I believe that it is appropriate to distinguish between power outages caused by system failures (e.g. transmission problems or localized distribution system outages) and power outages caused by serious natural catastrophes. Therefore, I believe that the Commission should consider suspending or adjusting these proposed rules when either the President of the United States or the Governor formally declare a State of Emergency.

Second, I have analytical and policy concerns whether there is sufficient evidence on the costs of the various proposed rules relative to the speculated benefits. Specifically, I asked my advisors to research the assumptions on how the specific **numerical** standards were determined and to give me a briefing on the concomitant cost benefit analysis which led to what is being proposed in the order. I am not satisfied with the answers they found to my questions. Therefore, I present these issues now to the parties for comment rather than delay the issuance of this important order. Parties should be mindful that I am truly committed to having a strong, sustainable regime in place to **[*41]** provide California citizens the peace of mind to know that emergency situations will be addressed properly and adequately by this Commission.

To put the issue in context, I believe that it is important for the two different types of outages to be segregated and dealt with clearly and effectively. Power outages caused by a failure in the utility system are very different from power outages caused by events outside the system, such as major catastrophes like earthquakes, fires or floods. I am not certain that, in the event of a serious earthquake, or fire or flood, it is reasonable for the Commission to expect a utility to make information available to customers during a predetermined or expected duration of an outage. I also question whether this is even possible if an event is also accompanied by major telecommunications outages in a given location. The proposed rules may lead to gold-plating a massive telecommunications infrastructure in order for the utility to meet the proposed standards when there are major outages as a result of natural disasters. This investment in infrastructure may prove to be useless if the same natural disaster impacts the state's telecommunications networks **[*42]** as well. Moreover, accompanying events may make the restoration criteria impossible to achieve during a major natural disaster. For example, all of the northeastern utilities would have violated these proposed standards a hundredfold during this winter's ice storms that paralyzed the delivery of all services to that region of the country.

My fears on this subject are not misplaced. History has shown California that we have our unfair share of natural disasters. Some say we have two seasons in California, fire season and flood season, in between which we await earthquakes. The Commission should be very careful not to set standards that are impossible to meet. Nor should we set excessively high standards bearing high implementation costs that will flow through to ratepayers. At this point in time, I am not convinced that the standards offered in this proposed decision are in the public interest because of their costs relative to public benefit.

Before I vote to impose final rules on California utilities, I will need compelling evidence that the proposals are grounded in reality, that the benefits of these standards outweigh their costs and that the standards will, in fact, improve the **[*43]** level of reliability of the system. The Commission's focus should be proactively increasing reliability of the system by virtue of these standards, rather than reactively finding fault after disaster strikes. I do not want to put the Commission in the unnecessary and unproductive position of having to play the blame game after a natural catastrophe, indeed a vestige of our old regulatory role. This is why it is vital we adopt realistic standards.

I vote in support of today's proposed order but look forward to reactions to my concurrence and statement in order to put the appropriate final rules into place.

Dated March 12, 1998 at San Francisco, California.

/s/ Jessie J. Knight, Jr.

Jessie J. Knight, Jr.

Commissioner

Commissioner P. Gregory Conlon, Concurring:

I support the need for the utilities to plan in advance for emergencies and to respond promptly in emergency situations. However, I believe that it is equally important to try and minimize up-front the impact that natural disasters (such as storms) have on the electric distribution system.

One means to minimize local electric outages due to storms and high winds is to underground the local distribution system. In my study **[*44]** tour of the United Kingdom's restructuring of its electric industry, I was highly impressed going throughout London and not seeing any above-ground wires.

Commission Rule 20A establishes a program to promote the undergrounding of the electric utility distribution system. This program is funded at a level of approximately 1-2% of each utility's gross revenue. The budget for this program for 1998 is approximately $ 128 million. This program requires that either local governments or the utility's customers also contribute to the cost of any undergrounding effort. Partially because of this, statewide there is almost $ 450 million in unutilized funding that has been carried over from previous years.

Some utilities, especially Pacific Gas & Electric, have been actively involved in implementing the undergrounding program and in searching out ways to increase program participation. I urge all of California's utilities to explore alternative methods to insure that all available undergrounding funds are utilized. I urge the utilities, as well as all other interested parties, to comment on this issue.

/s/ P. Gregory Conlon
P. Gregory Conlon

San Francisco, California
March 12, 1998

Legal Topics:

For related research and practice materials, see the following legal topics:
Communications LawU.S. Federal Communications CommissionJurisdictionEnergy & Utilities LawElectric Power IndustryElectricity Distribution & TransmissionState & Municipal OwnershipEnergy & Utilities LawUtility CompaniesLiability

CPUC Decision 02-04-026
Access to Medical Baseline on behalf of Disability Rights Advocates

Decision 02-04-026 April 9, 2002

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Determine Whether Baseline Allowances for Residential Usage of Gas and Electricity Should Be Revised	Rulemaking 01-05-047 (Filed May 24, 2001)

INTERIM OPINION
REGARDING PHASE 1 ISSUES

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I. Summary

In this first phase of our rulemaking on electric and gas baseline allowances, we increase the baseline allowances for many residential customers and begin the process of improving the medical baseline program. Specifically, we require the utilities to update the data used for calculating baseline allowances to reflect current usage of both gas and electricity, to increase baseline allowances to the maximum percentage levels allowed by state law for those customers not already receiving those maximum allowances, and to take steps to simplify and improve the process by which customers may obtain additional baseline allowances for medical reasons.

In the Order Instituting Rulemaking (OIR) dated May 24, 2001 opening this proceeding, we stated:

> In summary, it has become clear that baseline is an important topic that merits attention at a time when so many Californians are being affected by the largest energy rate increase this Commission has ever had to impose. Section 739, the baseline statute, was added to the Public Utilities Code by the legislature through passage of Assembly Bill 167, the Warren-Miller Energy Lifeline Act, in the 1975-1976 legislative session. After the Commission determined the initial baseline quantities in 1976, it made subsequent revisions and updates in the utilities' general rate cases over the years. Section 739(d)(1) requires, "The commission shall review and revise baseline quantities as average consumption patterns change in order to maintain these [50% to 60%, and 60% to 70% of average residential consumption] ratios." With our recent rate design relying so heavily on baseline quantities to determine which residential customers are affected and to what degree, it becomes more important than ever to ensure the baseline program is up to date. Now is an appropriate time to do such a review. (OIR pp. 5-6)

This decision is the first step in bringing the baseline program up to date. This first step, while significant in expanding the benefits of the baseline program, still provides only limited relief to California's ratepayers. Our actions in Phase 2 of this proceeding may provide additional relief, but as we noted in the OIR:

> While we will do our best to adjust baseline quantities to more accurately reflect current consumption levels and significant differentials between customers, we are limited in our review by the statutes setting baseline quantities well below average usage of customers. Because of this, even with revised and updated baseline quantities, the average customer may still find it difficult to reduce usage to baseline levels. (OIR pp. 5-6)

We do, however, begin to make the baseline program more consistent among utilities, which should make it more understandable than it has been in the recent past. In addition, our changes will have the effect of increasing the baseline quantities for most Californians.

Our actions today apply to all Commission-regulated gas and electric utilities, except where otherwise indicated. All changes we require these utilities to make shall be in place, at the utilities' option, by June 1, 2002, or when the utilities change from winter to summer baseline quantities. The single exception relates to updating consumption data, which should be done as follows: For the natural gas baseline allowance, the deadline for updating baseline consumption data shall be the beginning of the 2003-04 winter heating season (generally October 2003). For new electric baseline allowances, the deadline shall be the summer cooling season of 2003 (generally May-June 2003). If the Commission has not issued a decision updating utility data regarding baseline allowances at least 30 days prior to these season changes, the utilities shall file an advice letter implementing such baseline allowance changes.

This latter deadline only pertains to the requirement that utilities update energy usage data contained in Section III(A) and Ordering Paragraph 8 of this decision. In that section, the Commission orders utilities to use this proceeding (or others in certain cases) to update their consumption data. It is understandable that this process will take time. In some cases, the utilities will present new consumption data in this proceeding, but have not yet done so. In other cases, the utilities have already presented the data in other proceedings, but there has not yet been a Commission decision approving such data.

All other changes ordered in this decision – those discussed in Sections III(B) (raising baseline quantities to statutory maximums) and (E) (changing medical baseline program) – shall be implemented, at the utilities' option, either by June 1, 2002 or when the utilities switch to summer 2002 baseline quantities as set forth in Ordering Paragraph 12.

II. Scope Of This Proceeding

In the *Ruling of Assigned Commissioner and Administrative Law Judge Setting Prehearing Conference*, dated June 11, 2001, this proceeding was split into two phases. That ruling preliminarily identified the issues to be addressed in Phase 1 of this proceeding as:

1) Updating the energy usage data used by the Commission in calculating baseline quantities;
2) Determining the appropriate percentage of energy usage to use in calculating baseline quantities within the range specified by Public Utilities Code Section 739(d)(1);
3) Constructing possible changes to the medical baseline allowance; and
4) Devising suggestions for legislative changes.

Parties have suggested a range of implementation dates for any changes ordered by this decision, with some parties suggesting January 1, 2002, and others suggesting dates in the spring of 2002. In general, the utilities suggest the later dates. In view of the passage of time since the Phase 1 hearings, we will order that all changes required to be made in the baseline quantities as a result of this decision (except those covered in Ordering Paragraph 8 related to the longer process of updating consumption data) be in place, at the utility's option by June 1, 2002, or at the time the utility changes over to the summer season. While providing prompt relief to utility customers is our primary consideration, we must temper that goal with the acknowledgement that we are requiring the utilities to implement further changes in already complex and difficult times.

D. Rate Impacts Addressed in Phase 2

We must also consider the potential rate impact on those customers who would be required to bear the cost of an increase in baseline allowances. In an ideal world, we would, as some parties suggested, not change baseline allowances until all cost impacts of such a change were thoroughly studied. We will address cost impacts in an integrated manner in the second phase of this proceeding, ensuring that all rate impacts are evaluated together, rather than in a piecemeal fashion.

E. Medical Baseline

Disability Rights Advocates (DRA) presents a number of proposals for changes to the medical baseline program. Some of these proposals were quite specific, while others are very general, and still others call for future work by the utilities, or coordination between the utilities and other groups, including groups that are not parties to this proceeding.

1. Translating Medical Baseline Forms Into Languages Other Than English and Into Braille

a) Foreign Languages

DRA argues that medical baseline forms[12] should be made available in multiple languages, citing to the significant cultural diversity of California, which presumably extends to the customers eligible for medical baseline quantities as well. While not totally embraced by the utilities, DRA's proposal is reasonable. Those customers faced with both a serious medical condition and a language barrier may be doubly disadvantaged in their ability to pay their energy bills and to find out about programs that can offer them assistance.

We will require the utilities to provide medical baseline forms in multiple languages. Each of the four large utilities (PG&E, SCE, SDG&E and SoCalGas) shall, in addition to English, provide all medical baseline forms in Spanish and in the most prevalent Asian language in its service territory. This requirement is consistent with what we have done in connection with our Energy Efficiency program.[13] We also encourage these four utilities to provide medical baseline forms in additional languages, particularly languages spoken by significant percentages of their customers. In the alternative, these utilities may work with community groups to provide information on the medical baseline program in additional languages.

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[12] Medical baseline forms include both an enrollment or application form and a re-certification form. Discussions of unspecified "forms" include both types.

[13] *See* D.02-03-056.

We recognize that the smaller and multi-jurisdictional utilities may vary significantly in the proportion of customers who speak a language other than English, and some may not have significant numbers of customers eligible for medical baseline. We do not wish to impose on utilities and their customers the cost of preparing materials in other languages if those materials will be largely useless. Accordingly, in an effort to tailor today's decision to the range of utilities subject to this proceeding, we will only require that medical baseline forms be prepared in other languages if there may be a need for such forms. If more than 10% of a given utility's customers' primary language is any language other than English, that utility shall make its medical baseline forms available in the second most common language in its service territory. We also encourage these utilities to perform outreach on medical baseline in additional languages but will leave the determination governing the best approach to each utility.

In addition to providing forms in additional languages, DRA made other recommendations discussed below for revising the utilities' medical baseline forms. PG&E recommends that the preparation and distribution provision of new forms in other languages should only occur after the forms themselves are revised. This recommendation is reasonable and pragmatic, as it would avoid the translation and printing of forms that would quickly be superseded. Accordingly, utilities should defer the translation, preparation and distribution of medical baseline forms in other languages until the forms are revised and simplified by the process described in Section III(E)(2) below.[14]

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[14] This is purely a cost-saving measure, and should not be construed to limit any foreign language outreach that any utility is otherwise performing or considering for its medical baseline program.

b) Braille

DRA also proposes that information be made available in alternative formats, such as Braille. DRA states that conversion of materials into Braille and large print often requires only the provision of the document in electronic format. While providing medical baseline documents in electronic format sounds quite feasible, we do not have an adequate factual record to provide adequate direction to the utilities to implement this proposal. Among other issues, it is not clear what electronic format or formats would be required. Nor is it clear that requiring the utilities to prepare information in Braille would be either the most effective or the most cost-effective approach. Some utilities have indicated that they do have outreach programs for the visually impaired. We encourage all utilities to do such outreach through community organizations and state agencies that serve the blind and visually impaired.

While we do not require the utilities to provide medical baseline information in Braille at this time, all utilities should have all medical baseline information and forms available in large print, to be provided upon request.[15] Large print versions shall be made available immediately, and need not await the revision of the forms. During this interim period, these large print materials need not match the format of the standard size material, but may be a simple enlargement of the existing materials.

2. Simplification of Medical Baseline Forms

We concur with DRA that all medical baseline forms should be clear and simple, and some utilities have agreed to simplify their forms. DRA has also suggested that a standardized application form be developed that would be

[15] Large print means at least 16- to 18-point type.

common to all utilities. This proposal appears to have merit, and we establish a process here for developing standardized application and re-certification forms.

DRA should provide samples of the forms, as DRA believes they should appear, to all parties named on the service list in this proceeding within 30 days from the date of this order. DRA need not wait the 30 days, but may serve its samples earlier if they are ready. Within 30 days of the date that DRA provides samples of its suggested forms, the utilities shall and any other party may respond. All responses will be served on the service list in this proceeding, and responses may be made prior to the 30-day deadline. If DRA and the other parties that provided a response to DRA cannot agree on the content of the forms by 30 days after the utilities respond, all parties shall meet with the Commission's Energy Division, which will have authority to resolve any outstanding issues. DRA, the utilities, and other interested organizations are encouraged to meet informally outside of this framework, and may resolve this issue prior to the above dates. If such resolution is reached, the utilities shall send a report describing the resolution, including at least a copy of the agreed upon forms to all parties named on the service list in this proceeding, as well as to the Commission's Energy Division.

DRA makes several specific recommendations relating to the application forms, including a place for designating whether a customer has a visual disability, and whether a customer's disability is permanent. While we agree that both of these items should be on all forms, we believe that all changes should be addressed via the process described above. We do not want to mandate certain changes here, only to have those changes subsumed in another round of changes as a result of the above process, or have them somehow hinder the development of an integrated approach by the parties. We prefer a unified and integrated approach, rather than a series of potentially confusing and expensive iterations.

As guidance for the parties, we want to ensure that customers who are either visually or permanently disabled and who have been qualified as having that status not inadvertently lose that status through mere inaction, such as failure to check a box on a form.

There was some disagreement as to the optimum level of detail that forms should have regarding the customers' particular equipment. DRA advocated for forms requesting less equipment detail, while SCE indicated that equipment detail can be useful in providing the most appropriate and sufficient allowance to a customer. We will let the parties address this issue through the foregoing process, and we will prescribe an approach only if they cannot reach resolution.

3. Availability of Medical Baseline Forms

In addition to changes to the forms themselves, DRA recommends that forms should be available to anyone who requests one, and should also be available on the utilities' websites. We agree that medical baseline forms should be made available to anyone requesting such forms, whether or not that person is potentially qualified for medical baseline or even a customer of the utility. Friends, relatives, or caregivers of a qualifying disabled customer are likely to be among those trying to obtain forms, and should be able to obtain them easily. The utilities should confirm that their customer service personnel have easy access to the forms and readily provide the forms to anyone who asks for them.

We agree that medical baseline forms should be available on the utilities' websites (if they are required to or actually do maintain websites), but we also agree with PG&E that this posting may be deferred until the forms are updated. However, any utility that currently offers any customer form online must add its current medical baseline form to its website within 20 days of the date of this order. All other utilities should have the form available on the website within 30 days of the revised form becoming available. All utilities should have information about medical baseline on their websites, including a telephone number to call to request medical baseline forms, and a means to request medical baseline forms by e-mail, within 20 days of the date of this order.

4. Outreach

a) CARE Programs

DRA recommends that outreach for the medical baseline program be integrated with the outreach for California Alternate Rates for Energy (CARE) programs, citing to statistics indicating a linkage between disability and low income. While DRA raises a valid issue, it does not provide specific details on how this could best be accomplished. In addition, SoCalGas raised concerns that combining medical baseline information on all CARE forms could result in customer confusion. We believe that this is also a valid concern and are reluctant to take any steps in this proceeding that could adversely impact enrollment of eligible customers in the CARE program. Thus, we will not order that CARE forms or brochures include information on medical baseline. We will order that the utilities with CARE programs inform organizations involved in CARE outreach of the existence of the medical baseline program, if they have not already done so, and inform those organizations of the availability of forms and information relating to medical baseline.

b) Other Outreach

DRA recommends that the utilities perform outreach on medical baseline with Independent Living Centers and Senior Organizations.

This is a reasonable and practical recommendation, as these organizations are likely to have contact with and knowledge of disabled populations at the community level. We direct the utilities to perform reasonable outreach to Independent Living Centers and Senior Organizations in their service territories. In their compliance advice letters, utilities should describe in detail how they are performing this outreach.

5. Recertification

DRA advocates reduced recertification requirements, particularly for those customers with permanent disabilities, citing to the difficulty often experienced by the disabled in obtaining a doctor's signature. Those customers certified as having a permanent disability will need to self-certify their eligibility, in lieu of obtaining a physician's signature or authorization, every two years to ensure their continued residence at the service address. Those customers not having a permanent disability will need to self-certify each year, and they will need to obtain or secure a doctor's certification every two years.

6. Size of Medical Baseline Allowance

While the size of medical baseline allowances was not a particularly controversial issue, Sierra Pacific has acknowledged that its electric medical baseline quantity is currently only 8.9 kilowatt per hour (kWh) per day in the winter and 6.5 kWh per day in the summer, compared with higher allowances of the three large electric utilities. Sierra Pacific has recommended that its medical baseline allowance be reevaluated in its next general rate case. We will order Sierra Pacific, and any other electric utilities whose electric medical baseline allowance is lower than that of the three major electric utilities, to revise their medical baseline allowance upward to match that of the three major electric utilities in this proceeding, and to implement this change within 30 days of the

Decision 04-10-034 October 28, 2004
INTERIM OPINION ON STORM AND RELIABILITY ISSUES

Decision 04-10-034 October 28, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Revenue Requirements for Electric and Gas Service and to Increase Rates and Charges for Gas Service Effective on January 1, 2003.	Application 02-11-017 (Filed November 8, 2002)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Pacific Gas and Electric Company.	Investigation 03-01-012 (Filed January 16, 2003)
Application of Pacific Gas and Electric Company Pursuant to Resolution E-3770 for Reimbursement of Costs Associated with Delay in Implementation of Pacific Gas and Electric Company's New Customer Information System Caused by the 2002 20/20 Customer Rebate Program.	Application 02-09-005 (Filed September 6, 2002)

INTERIM OPINION ON STORM AND RELIABILITY ISSUES

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1. Summary

This interim decision addresses Storm and Reliability issues raised in PG&E's General Rate Case (GRC) for test year (TY) 2003. Today's decision evaluates PG&E's response to the December 2002 storms and PG&E's reliability performance in general. We approve several "improvement initiatives" identified by PG&E in response to problems with the Outage Information System (OIS) and Customer Information Systems that arose during the December 2002 storms. We find that PG&E's recommended initiatives are likely to improve outage communication and reduce outage duration and should be approved. We approve a change in the call center measurement standard requested by PG&E.

Today's decision also considers joint testimony submitted by PG&E and the Office of Ratepayer Advocates (ORA) addressing the issues raised by ORA's testimony. With regard to the PG&E/ORA joint proposal, we concur with six of the Agreements, modify two of the Agreements, and reject one of the Agreements. We do not adopt Agreement 6 of the PG&E/ORA joint proposal. As discussed in this decision, we believe that the existing value of service data is too dated to rely on, and that little would be gained by further "assessment" of this data. In lieu of the value of service assessment proposed in Agreement 6, we direct PG&E to conduct a new value of service study prior to its next GRC. This decision approves Agreement 7 with modifications.

The decision also addresses the reliability performance incentive mechanism presented in joint testimony filed by PG&E and the Coalition of California Utility Employees (CUE). We adopt the PG&E/CUE performance incentive mechanism with modifications. We find that the PG&E/CUE performance incentive mechanism as proposed is not in the public interest because the performance targets fail to appropriately account for existing

funding commitments and commensurate reliability improvements, and the mechanism would result in an unjustified increase in PG&E's revenue requirement. However, we find that a more narrowly refined performance incentive mechanism than proposed by PG&E/CUE has value in encouraging improvements in system reliability.

Today's decision does not find that PG&E's response to December 2002 storms was reasonable. Our review of PG&E's response to the December 2002 storms finds that while the multiple outages and severe damage caused by the storm were not the result of PG&E's performance, the inadequacy of PG&E's OIS resulted in several unacceptable consequences, including customers being unable to receive accurate outage information in a timely manner, certain single customer outages being extended for an unnecessary amount of time, and emergency personnel being required to stand by hazardous conditions for excessive periods of time during the storms.

2. Procedural Background

In response to customer concerns regarding PG&E's storm performance and system reliability following a series of storms occurring in December 2002, the Assigned Commissioner in Application (A.) 02-11-017, PG&E's TY 2003 GRC application issued an Assigned Commissioner's Ruling (ACR) seeking supplemental testimony concerning PG&E's electric distribution service during both normal and storm conditions and establishing a separate phase of the GRC proceeding to evaluate PG&E's response to the storms and its readiness for them.

In establishing a separate storm and reliability phase, the ACR explained that this phase of the proceeding was "not designed to focus only on PG&E's performance in the December 2002 storms or in individual circuits, but rather to allow us to gain a fuller understanding of the resources PG&E invests in reliability, maintenance, and emergency response efforts and how resources are

	SAIDI excluding Major Events	SAIFI excluding Major Events
2005	165	1.40
2006	161	1.33
2007	157	1.24
Deadbands	10 min/yr	0.10 outages/yr
Livebands	15.8 min/yr	0.15 outages/yr
Max Annual Reward/Penalty	$12 million	$12 million

b. Employee Safety Mechanisms

CUE proposes that the Commission adopt an employee safety mechanism to prevent PG&E from cutting corners on safety in order to save money. CUE argues that an employee safety mechanism is particularly important in the context of reliability performance incentives, where there is a direct financial incentive to restore service as quickly as possible. CUE recommends that the mechanism be based on the OSHA recordables frequency rate, with the benchmark set at 5.42, PG&E's most recently attained safety level.

PG&E opposes CUE's recommendation, arguing that PG&E already has a comprehensive program to promote safety and health and manage the incidence of injury and illness in the workplace. PG&E states that its program has yielded continued and sustained improvement in safety and health in recent years. PG&E also argues that changes in the OSHA regulations for reporting injury or illness that took effect on January 1, 2002, make it impossible to develop an OSHA recordables metric that accurately compares recent statistics with historical records in any meaningful way. PG&E states it now uses Lost Workdays as the basis for monitoring and evaluating its safety performance as opposed to the OSHA recordables rate, because it believes that lost work time is the most accurate measure of the severity of injuries or illnesses. PG&E argues that the Commission should not adopt CUE's proposed employee safety incentive mechanism because it relies on unreliable data to measure PG&E's safety performance.

CUE admits that PG&E's OSHA recordables rate has continually improved. PG&E's OSHA recordables rate has gone from a high in 1993 of 11.16 to 5.43 incidents in 2002. Given the fact that PG&E's employee safety performance has been consistently improving and we do not adopt a reliability performance incentive mechanism, we find that there is no need to adopt an employee safety incentive mechanism at this time.

c. Call Center Metrics

Under D.95-09-073, PG&E is required to maintain a monthly ASA of 20 seconds, with monthly busy signals a maximum of 1 percent during normal times and 3 percent during outages. PG&E met this standard from January 1998 to December 2002 with only two exceptions that occurred during the energy crisis. After the installation of its new CIS, however, PG&E has been unable to meet the ASA standard. PG&E requests that the Commission adopt a TSL standard instead of the ASA standard. PG&E notes that it is the only utility that is subject to an ASA standard and that its request to switch to a TSL standard is uncontested.

TURN does not oppose PG&E's request, as long as the new standard reflects the same level of service as the existing ASA standard. TURN states that an ASA standard of 20 seconds is equivalent to a TSL standard of 80/20, or 80 percent of the calls answered in 20 seconds. TURN notes that PG&E's current call center situation requires longer wait times for live customer service representatives and a longer time on the phone to handle business in comparison to the previous CIS system. TURN points out that PG&E's 2003 revenue requirement request includes funding to maintain the Commission's 20 second ASA standard. PG&E's call center request incorporates an ongoing increase of $4.63 million (nominal dollars) for additional labor required to compensate for the expected lower efficiency in the new CIS and some increased call volume.

TURN also notes that the ASA standard includes calls answered by PG&E's VRU. During normal conditions, PG&E's customer service representatives answer 60-70% of the calls. Under storm conditions, the VRU handles a larger proportion of calls, such that it is possible that the ASA remains at 20 seconds or less, but the wait time for a representative is much longer. For example, on December 16, 2002, the day of peak call volume of the December storms, the ASA was 12 seconds, with 96% of calls answered in 20 seconds, yet the maximum wait time for a service representative was 76 minutes, and 12% of calls to the customer service representatives were abandoned. Nevertheless, TURN does not recommend that the Commission apply a stringent call center standard on a daily basis for storm conditions at this time, because it would be too expensive.

We agree with TURN that any new standard adopted should reflect the same level of service as the old standard. Since the TSL standard of 80/20 or 80% of calls answered in 20 second is equivalent to an ASA standard of 20 seconds, we will approve PG&E's request and adopt a TSL standard of 80% in 20 seconds. However, since neither the ASA standard nor the TSL standard currently differentiates between the response time associated with calls answered by a service representative and the response time associated with calls answered by the VRU, we find that the statewide workshops to be instituted under

PG&E/ORA Agreement 3, above, should address whether or not call center standards should be revised to better reflect the use of VRU. In particular, the workshop participants should recommend a standard of reasonableness of Average Handle Time in addition to an ASA or TSL standard.

8. Conclusion

With each major storm event and subsequent investigation, it is a challenge to balance the desire to respond immediately and specifically to the unique circumstances that arise against the need to carefully review each event and avoid a crisis management response. We firmly believe that it is of little value to adopt standards that apply to situations of limited duration or that are unlikely to repeat themselves. This proceeding is no exception. Our primary objective in PG&E's TY 2003 GRC is to ensure that PG&E continues to provide utility service at the lowest reasonable rates, maintaining a high level of customer service and satisfaction, and a safe working environmental for its employees. In this phase of the GRC, we are reviewing PG&E's overall reliability performance and storm response to determine whether PG&E has met this level of service and whether additional standards or metrics are necessary to ensure that PG&E continues to provide this level of service. Our detailed review was focused mainly on controversies which arose between PG&E and other parties and a comparison of PG&E's performance to previously-established performing standards.

The December 2002 storms consisted of a series of four severe storms that occurred within a period of nine days. These storms severely tested PG&E's facilities and staff and highlighted many weaknesses in PG&E's organization. While PG&E maintains that its overall reliability performance was reasonable, it admits that its performance during the December 2002 storms requires improvement, especially in the area of outage communications, and has identified several initiatives designed to prevent similar situations from occurring in the future. Other parties also proposed various measures designed to improve PG&E's performance.

While we approve the majority of the PG&E/ORA Agreements, we adopt the PG&E/CUE proposal for a performance incentive mechanism only with main provisions modified. Based on the record in this case, the PG&E/CUE Joint Proposal as presented is not in the ratepayer's interest. We find that the incentive proposal is not likely to result in achieving our basic regulatory objective of maintaining the lowest reasonable rates consistent with safe, reliable, and environmentally sensitive utility service because it would place ratepayers at a significant risk of paying for the same level of reliability two or three times. However, we do find some elements of the mechanism to provide value to encourage improvements in system reliability.

Under cost of service ratemaking, our objective is to adopt a revenue requirement that allows the utility to provide high quality service at just and reasonable rates. Adopting a revenue requirement necessarily includes a presumption of a certain service level. While we support PBR-style incentives in concept, the incentives must be consistent with and not jeopardize our other regulatory goals. We must also avoid using incentives as a substitute for the utilities' statutory obligation to provide high quality service, especially in monopolistic utility markets. In this case, we find that the combination of traditional cost of service regulation and the proposed PG&E/CUE incentive mechanism is likely to result in ratepayers paying twice for the same level of reliability.

As stated above, we direct PG&E to prepare a value of service study prior to its next GRC. The updated value of service information will inform the

Commission regarding PG&E's customers' desire for and willingness to pay for increased reliability.

Although we find that PG&E has provided adequate service during normal conditions, based on the record in this proceeding, we also find that PG&E's outage communications during the December 2002 storms do not reflect a reasonable level of service. PG&E has admitted that its storm response needs improvement, but maintains that, on an overall basis, its response to the December 2002 storms was reasonable. We disagree. We believe that while the record demonstrates that the outages and damages caused by the storms were reasonable considering the severity and the back-to-back nature of the storms, given the many outage communication and call center problems that occurred during the storms, we cannot find that PG&E's storm response was reasonable. In particular, PG&E concedes that its method for addressing single customer outages failed, resulting in single customer outages being unrecorded and unresolved. PG&E also admits that calls from emergency personnel were handled in a manner that resulted in police and fire personnel standing by hazardous conditions for excessive periods of time during the storms. Given this evidence, we cannot find that PG&E's overall storm response was reasonable. However, based on the fact that PG&E has admitted its deficiencies and begun implementing remedial measures, we do not find that any sanctions or penalties are necessary. We also note that none of the parties requested sanctions or penalties related to PG&E's storm response.

9. Comments on Alternate Proposed Decision

The alternate proposed decision of the Commissioner Susan Kennedy in this matter was mailed to the parties on October 14, 2004, in accordance with Section 311(d) of the Public Utilities Code and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on October 21, 2004, and reply comments were filed on October 26, 2004.

10. Assignment of Proceeding

The Assigned Commissioner in this proceeding is Michael R. Peevey and the assigned ALJ is Julie M. Halligan. The February 13, 2003 ACR determined that this was a Ratesetting proceeding and designated the assigned ALJ as the principal hearing officer as defined in Rule 5(l) of the Commission's Rules of Practice and Procedure.

Findings of Fact

1. In December 2002, Northern California experienced a series of severe storms, with high winds and heavy rainfall.

2. These storms caused significant damage to PG&E's electric distribution and transmission facilities, resulting in 1.97 million customer interruptions.

3. PG&E has an obligation under statute to provide highly reliable electric service at minimal cost.

4. The level of service reliability provided by PG&E during normal conditions from 1999 through 2002, as measured by SAIDI and SAIFI, is consistent with the reliability performance standards identified in D.00-02-046.

5. SAIDI, SAIFI, and MAIFI are useful methods of collecting and assessing data on the frequency and duration of system disturbances.

6. It is not particularly useful to compare reliability performance among utilities based on SAIDI, SAIFI, and MAIFI, since different customer counts, system design, geography, weather patterns, and methods of calculating outage duration of the individual utilities will necessarily result in differing performance.

7. PG&E has not prepared a value of service study for at least ten years.

8. The record in this proceeding does not contain value of service information that sufficiently captures the significant changes that have occurred in the electric industry or the California economy in the last decade.

9. The value of service estimates contained in PG&E's Utility Operations Guideline 12003 do not adequately represent PG&E's customers' current value of service and should not be used as the basis for incentive payments or funding.

10. The significant difference in reliability performance between PG&E's divisions favors adoption of division-level performance indicators.

11. PG&E was authorized $34 million in ratepayer funding for a new OIS in its last GRC and seeks approval for $16 million in this GRC for additional OIS improvements over the term of the GRC.

12. Ratepayers have already funded an OIS and a FAS designed to address single customer outages in a coordinated manner.

13. PG&E's request for $3.05 million in expense to upgrade the software for the mobile data terminals is a one-time activity.

14. PG&E's proposal to amortize the cost of enhancing the mapping associations within its OIS over a period of four years will allow the expense to be recovered over a period of time consistent with the expected length of the effort and the amount of projected expenditures per year and should be approved.

15. Adoption of the division-level reliability reporting requirements included in PG&E/ORA Agreement 1 will prevent system-level measures from masking division level performance.

16. Adoption of division level reliability measures as the primary measure of reliability is unnecessary at this time because the Commission may consider either system level measures or division level measures in its determination of reliability performance.

17. There is a need to address definitions of Excludable Major Event, Major Outage, and Measured Event, as well as the restoration performance standard included in Standard 12 of General Order 166.

18. The record in this case supports the fact that PG&E's customers desire improved storm response.

19. The record in this case does not support the fact that PG&E's customers are willing to pay for increased reliability generally.

20. PG&E and CUE have not shown that the proposed incremental annual revenue requirement will increase reliability beyond the levels reasonably expected to result from PG&E's base TY 2003 GRC request.

21. TURN and ORA have demonstrated that PG&E's reliability performance, as measured by the SAIDI and SAIFI performance indicators, is likely to improve without incentive revenues if PG&E pursues the projects proposed in its base TY 2003 request.

22. Given the fact that PG&E's employee safety performance has been consistently improving there is no need to adopt an employee safety incentive mechanism at this time.

23. The statewide workshops to be instituted under PG&E/ORA Agreement 3 should address whether or not call center standards should be revised to better reflect the use of VRU since neither the ASA standard nor the TSL standard differentiates the response time associated with calls answered by a service representative and calls answered by the VRU.

24. The level of service achieved by an ASA standard is equivalent to the level of service provided by a Telephone Service Level Standard of 80% of the calls answered in 20 seconds.

25. Different utilities record reliability metrics using different methodologies, making inter-utility comparisons difficult.

26. There is value in adopting a set of targeted expectations for SAIDI, SAIFI through a performance incentive mechanism.

Conclusions of Law

1. The Commission is required by Pub. Util. Code § 451 to ensure that PG&E's customers receive reliable electric service at just and reasonable rates.

2. Allowing PG&E to collect and retain more revenue than is reasonably necessary for it to provide safe and reliable utility service would be contrary to the law.

3. PG&E bears the burden of proof to support its application through clear and convincing evidence.

4. PG&E should implement the "improvement initiatives" identified in this decision that would improve PG&E's OIS, thereby improving PG&E's storm response and reliability performance.

5. Agreements 1, 2, 3, 4, 5, 8 and 9 of the PG&E/ORA Joint Testament are in the public interest and should be approved.

6. It is in the public interest that the reliability metrics collected by the regulated electric utilities in California be standardized to allow the Commission and the public to have better understanding of the reliability of the utility electric distribution systems.

7. PG&E and the other proponents of performance incentives have sustained their burden of proving that the incentives are necessary and appropriate and proposals to implement such incentives, including the joint motion of PG&E and CUE, shall be granted with modifications.

8. PG&E's last value of service study was prepared in 1993, with updated estimates prepared for a September 2000 PBR application.

9. PG&E should be directed to conduct a new value of service study prior to its next GRC.

10. In order to allow ORA to review and comment on PG&E's proposed approach and format for the value of service study, PG&E should file an advice letter that sets forth PG&E's proposed approach to conducting the value of service study and a proposed budget for Commission consideration.

11. Ratepayers should not be forced to fund the same OIS functionality twice.

12. PG&E/ORA Agreement 7 should be modified to remove funding for the single customer outage issue and amortize the expense of funding the software upgrades for the mobile data terminals and the mapping association enhancement project over 3 and 5 years, respectively.

13. PG&E's request for $2.45 million in expense and $0.8 million in capital for programming changes to include single customer outages in the OIS should be denied.

14. Approval of a Reliability Memorandum Account to record the costs of approved upgrades to PG&E's OIS would not result in retroactive ratemaking.

15. PG&E should be permitted to establish a memorandum account to track the costs associated with authorized OIS Improvements.

16. The Commission's Energy Division should convene statewide workshops to review the definitions of Excludable Major Event, Major Outage, and Measured Event with the intention of reviewing, clarifying and combining the definitions in D.96-09-045 and GO 166 into a common definition that clearly standardizes the criterion regarding the percentage of customers, or percentage of facilities, that must be affected before an event is considered excludable, including how percentages are to be calculated (i.e. cumulative or simultaneous) and how the start and end times are to be determined.

17. PG&E's request to change from an ASA metric to a telephone service level metric is reasonable, and should be approved.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall implement the following customer service and Outage Information System (OIS) improvements:

   a. Modify restoration prioritization to balance the length of time small numbers of customers are out of power with the need to restore the largest number of customers as quickly as possible;

   b. Simplify the routing of calls from emergency agencies to PG&E to improve the dispatching of PG&E resources to relieve police and fire agency personnel of the need to stand by on site;

   c. Develop additional software to enhance the ability within OIS to increase focus on single customer outages during major events to improve communication with customers and reduce outage duration;

   d. Link its OIS with the mobile data terminals in the field to accelerate the input of outage cause and damage assessment information into the Operations Emergency Centers and estimated time of restoration data into the OIS to improve the speed of assessing damage and sharing outage information with customers;

   e. Integrate the three existing outage databases (the Supervisory Control and Data Acquisitions, OIS and Distribution Operators Logging Information Program) to reduce the number of manual entries an operator must make to improve efficiency and reduce outage duration;

   f. Enhance mapping associations within the OIS so that smaller portions of PG&E's circuitry can be pinpointed for purposes of determining on a real-time basis a more accurate number of customers affected by outages and more accurate outage information;

g. Add new toll-free numbers for customers who are without power for more than 48 hours; and

h. Implement a campaign to urge customers to verify the accuracy of the phone number on their PG&E bill.

2. PG&E shall implement Agreements 1, 2, 3, 4, 5, 8 and 9 of the PG&E/Office of Ratepayer Advocates (ORA) joint testimony, as described in Appendix A.

3. PG&E shall submit division-level reliability data annually, concurrent with the system-level reliability report required by D.96-09-045. The reliability measures will include division level average interruption duration, average interruption frequency, customer average interruption duration and momentary average interruption frequency.

4. PG&E shall investigate and report to the Commission when the division level Average Interruption Frequency Index, Customer Average Interruption Duration Index (CAIDI) and Momentary Average Interruption Frequency Index (MAIFI) vary by 10 percent or more in any division from the five-year rolling average of reliability performance.

5. The Commission's Energy Division shall schedule workshops consistent with ORA/PG&E Agreement 3 within 90 days of this decision.

6. PG&E shall perform, or cause to be performed, a customer value of service study prior to its next General Rate Case (GRC). PG&E shall file an Advice Letter with the Commission within 90 days of this decision detailing its proposed value of service study approach and cost estimate for Commission review and approval.

7. PG&E is authorized to establish a memorandum account (consistent with the Reliability Improvement Memorandum Account proposed in PG&E/ORA Agreement 7) to track the following costs associated with funding the following OIS upgrades:

a. $3.050 million in expense, amortized over three years, to link the OIS to the mobile data terminals;

b. $3.250 million in expense to integrate the three existing outage databases (Supervisory Control and Data Acquisitions, OIS and Distribution Operators Logging Information Program; and

c. $7.360 million in expense ($460,000 in 2003 and $2.3 million in each of the years 2004, 2005 and 2006) to enhance the mapping associations within the OIS so that smaller portions of PG&E's circuitry can be pinpointed.

The amount incurred in 2003 is recoverable to the extent that PG&E's actual expenses in Federal Energy Regulatory Commission (FERC) Account 588 exceed 2003 GRC adopted FERC Account 588 expenses by the amount that actual expenses exceed adopted expenses up to the amounts in the Memorandum Account. For the expenses incurred in 2004, 2005 and 2006, the amounts are recoverable up to the above incremental amounts to the extent that PG&E's total electric O&M expenses exceed GRC adopted O&M expenses.

8. PG&E shall be subject to the targeted reliability metrics as outlined in section 7.5 above.

9. We order Commission staff to prepare an Order Instituting Rulemaking into standardizing the reliability metrics for California's regulated utilities, to be available for Commission vote within nine months of this order. This OIR shall present various issues that the proceeding shall address, including (but not limited to) those presented in Section 7.4 of this Decision.

10. Within 10 days of the effective date of a final decision on Phase 1 of PG&E's Test Year 2003 GRC, PG&E shall file revised tariff sheets to implement the revenue requirements and accounting procedures set forth in this decision.

This order is effective today.

Dated October 28, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I dissent.

/s/ LORETTA M. LYNCH
Commissioner

I dissent.
/s/ CARL W. WOOD
Commissioner

Decision 05-08-037 August 25, 2005
OPINION ON THE REASONABLENESS OF SAN DIEGO GAS AND ELECTRIC COMPANY'S RESPONSE TO THE 2003 WILDFIRES

Decision 05-08-037 August 25, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SAN DIEGO GAS & ELECTRIC COMPANY under the Catastrophic Event Memorandum Account (CEMA) for Recovery of costs related to the 2003 Southern California Wildfires. (U 902-M)	Application 04-06-035 (Filed June 28, 2004)

OPINION ON THE REASONABLENESS OF SAN DIEGO GAS AND ELECTRIC COMPANY'S RESPONSE TO THE 2003 WILDFIRES

(*See* APPENDIX A for Appearance Lists)

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1. Summary

The firestorm of 2003 was the largest disaster of this type ever to occur in the State of California. Nearly 400,000 acres were burned, 16 lives were lost and more than 2,400 homes were destroyed in San Diego County alone. SDG&E experienced severe damage to its infrastructure with approximately 3,200 power poles, 700 spans of wire, 400 transformers and more than 100 other pieces of related equipment damaged and needing to be replaced. In total, approximately 108,000 of SDG&E's electric customers and 2,050 gas customers were left without service as a result of the firestorm.

By November 2, 2003, only one week following the start of the fire, SDG&E had restored service to more than 102,000 electric customers and had successfully restored service to the remaining 6,000 customers primarily living in areas of rugged terrain by November 20, 2003. This exceptional effort has been the subject of numerous accolades and commendations from customers as well as government officials thanking the Company for a job well done.

This decision finds San Diego Gas & Electric Company (SDG&E) prudently managed its response to the firestorm of 2003 in its service territory and allows the recovery of certain recorded costs incurred to restore service and repair or replace those portions of its gas or electric distribution systems damaged or destroyed by a series of catastrophic wildfires. This decision allows SDG&E to recover the full amount of its request, $40.8 million.

2. Background

On June 28, 2004, SDG&E filed an application to recover $37.6 million, the California jurisdictional costs associated with the 2003 Southern California Wildfires (Wildfires). Applicant asserts the memorandum account (Wildfire Account) is in conformance with its Catastrophic Event Memorandum Account (CEMA) tariff as authorized in its Preliminary Statement. Including updates through December 2004, SDG&E spent $71.163 million in total, allocated $8.441 million to transmission service subject to the Federal Energy Regulatory Commission's (FERC) jurisdiction and the balance of $62.722 million to California- jurisdictional gas and electric service. SDG&E reduced this amount by $21.9 million to reflect funds already authorized in rates. The remaining $40.8 million are the residual incremental costs that are the subject of this proceeding.

a. History of the Wildfires

SDG&E described the Wildfires by citing[1] a joint report of the U.S. Forest Service and the California Department of Forestry and Fire Protection, "In October of 2003, Southern California experienced the most devastating wildland fire disaster in state history. The facts are staggering – 750,043 acres burned, 3,710 homes lost and 24 people killed including one firefighter."[2] The report further states:

> The October Fire Siege of 2003 tested the modern fire service like no other time. The combined efforts of the largest wildland fire agencies in the world, the United States Forest Service and the California Department of Forestry and Fire Protection (CDF), along with armies of local fire departments across the state mustered ground and air resources into the firefight as never before. At the peak of the fire siege, over 14,000 firefighters were on the line. Never in California's history were so many homes and lives in danger by fire at one moment . . . . In addition, countless miles of power lines were damaged, communication systems destroyed, watersheds reduced to bare scorched soils, and thousands of people were forced

[1] Application, pp. 1-2.

[2] As quoted in the Application, from "California Fire Siege 2003 – The Story: October 21 – November 4, 2003" (Preface).

> into evacuation centers, unsure if they would have a home to return to – many did not.[3]

SDG&E further indicates that it believes no area in Southern California may have been harder hit by the wildfires than San Diego County. It states that approximately 3,200 power poles, 400 miles of wire, 400 transformers and more than 100 other pieces of related equipment were damaged by the fire and needed to be replaced. Over 2,400 homes were destroyed and countless other structures were damaged by these wildfires. In addition, SDG&E presents detailed testimony on the scope of the damage to its system attributed to the fire and the response to repair and replace the damage.[4]

In order to invoke and employ the Wildfire Account, SDG&E must demonstrate that the circumstances surrounding the Wildfires meet the conditions for a catastrophic event account as defined in Pub. Util. Code (Code) Section 454.9(a), for restoring utility services to customers, repairing, replacing, or restoring damaged utility facilities, and complying with governmental agency orders in connection with events declared disasters by competent state or federal authorities. Such costs are recoverable only after the Commission makes a finding of their reasonableness and approves them following an expedited proceeding in response to the utility's filed application (Code § 454.9(b)). This proceeding was conducted on a schedule designed to result in a prompt decision after first ensuring due process was provided to all parties.

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[3] As quoted in the Application, *Id.* (Introduction).

[4] Ex. SDG&E-1, Testimony of Steven D. Davis and in more detail in Ex. SDG&E-2, Testimony of Scott P. Furgerson.

On October 26, 2003, then-Governor Davis declared a state of emergency in San Diego County. The following day, October 27, 2003, President Bush also declared a state of emergency in San Diego County. In addition, the County of San Diego and the City of San Diego also declared states of emergency on October 28, 2003 and November 3, 2003, respectively. SDG&E invoked its CEMA tariff in response to this catastrophic event, and, in accordance with Resolution No. E-3238,[5] notified the Commission's Executive Director on November 24, 2003.[6] The first table below is from Ex. 3 and it shows SDG&E's original cost basis for the request before applying the incremental cost test discussed later in this decision. The second table is from Ex. 4 and it shows the $37.661 million portion of $58.011 million California-jurisdictional costs (through May 2004) that SDG&E claims are reasonable for inclusion in the memo Account and recoverable from ratepayers. As described in SDG&E's testimony, $20.35 million was identified to be already available in rates to fund the Wildfire's costs. The residual $37.661 million is described as incremental costs, not otherwise provided in rates, and therefore eligible for recovery.[7] The net request is for $37.309 million for electric costs and $0.352 million for natural gas costs.

The testimony and evidentiary hearings focused on those costs increased through May, 2004. SDG&E provided two late-filed exhibits

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[5] CPUC Resolution E-3238, dated July 24, 1991.

[6] Application, p. 3.

[7] There are some slight rounding differences in the two exhibits that are not material here. In the adopted recovery we identify the accurate reasonable jurisdictional allocation.

(SDG&E-9 and SDG&E-10) that updated actual costs through December, 2004. Those costs are discussed in a separate section of this decision. Parties reviewed the late-filed exhibits and filed comments that are considered in this decision.

Proposed Recovery of Wildfire Account Costs Through May 2004

	Total CPUC (a)	Memo Account (b)	Current Rates(b)
O&M Expenses:			
Internal Labor	$ 3,575	$ 2,250	$1,324
Materials	1,309	1,290	19
Overhead	2,538	251	2,288
Vehicle Charges	436	-	437
External Labor	718	7,546	341
Services/Other	7,887	7,546	341
Total O&M	$ 16,463	$12,055	$ 4,408
Capital Costs:			
Internal Labor	$ 5,596	$ 4,060	$ 1,536
Materials	2,769	2,769	-
Overhead	13,512	636	12,876
Vehicle Charges	1,505	-	1,504
External Charges	1,5883	1,5883	-
Services/Other	2,283	2,257	27
Total Capital	$ 41,548	$ 25,605	$ 15,943
Total Wildfire	$ 58,011	$ 37,661	$20,350

(a) Ex. 3 Attached Ex. D-1.
(b) Ex. 4, Attached Ex. J.

3. Procedural History

Notice of the Application appeared in the Commission's July 1, 2004 daily calendar. Resolution ALJ 176-3136, dated July 8, 2004, preliminarily categorized the application as ratesetting and determined that hearings were necessary. The Commission's in-house consumer advocacy arm, the Office of Ratepayer Advocates (ORA) filed a timely protest on July 30, 2004. On July 14, 2004,[8] the

[8] *Administrative Law Judge's Ruling Requiring San Diego Gas & Electric Company to Provide Further Information to Supplement its Application.* The Ruling identified 6 specific

Footnote continued on next page

ALJ required SDG&E to serve supplemental testimony. On July 29, 2004, SDG&E served the requested supplemental testimony as Ex. SDG&E-4. On October 29, 2004[9], the ALJ required SDG&E to further supplement the testimony contained in EX. SDG&E-4 and on November 10, 2004, SDG&E served Ex. SDG&E-7 in response. A Prehearing Conference was held on August 17, 2004 and ORA, the Aglet Consumer Alliance (Aglet) and the Utility Consumer Action Network (UCAN) served timely prehearing Conference Statements.

On August 27, 2003 *The Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* (Scoping Memo) designated the assigned Administrative Law Judge (ALJ) as the principal hearing officer as defined in Rule 5(l) of the Rules. It also determined that this is a ratesetting proceeding. Pursuant to Rule 5(k)(2), the principal hearing officer is the presiding officer for this proceeding, and is responsible for issuing the proposed decision pursuant to Code § 311(d) and Rule 8.1.

The scope of this proceeding was identified[10] as:

- Reasonableness of SDG&E's overall management of the restoration of service in a safe and timely manner, consistent with worker safety, public need, and equitable treatment of customers.
- Reasonableness of the gross amount of Operating & Maintenance Expenses recorded in the Wildfire Account.

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deficiencies and directed SDG&E to provide adequate documentation or further explanations, as appropriate, in the form of additional testimony.

9 *Administrative Law Judge's Second Ruling Requiring San Diego Gas & Electric Company to Provide Further Information to Supplement its Application.*

10 Scoping Memo, pp. 3-4.

- Reasonableness of the gross amount of Capital Expenditures recorded in the Wildfire Account.
- Reasonableness of SDG&E's determination of incremental costs as defined by Resolution E-3238.
- Reasonableness of the forecast 2005 ongoing capital-related costs of $4.3 million for electric distribution and gas revenue requirements. This includes an analysis of any 2005 incremental or avoided expense or capital expenditure impacts on SDG&E's subsequent operations as a result of service restoration after the Wildfires.
- Allocation of all costs between the jurisdictions of the Federal Energy Regulatory Commission and the California Public Utilities Commission.
- The reasonableness and timing of SDG&E's proposed ratemaking treatment of any authorized recovery of the Wildfire Account balances.

Testimony was served by ORA and UCAN on October 22, 2004. Evidentiary hearings were conducted on November 15 – 16, 2004, and over 20 exhibits were received in evidence. All issues are ready for consideration.

In accordance with the Scoping Memo, opening and reply briefs were filed by SDG&E, ORA, and UCAN, on December 3, 2004 and December 10, 2004, respectively. A late-filed exhibit, Ex. SDG&E-9, was served to update the balance in the Wildfire Account. It was received into evidence on January 18, 2004, and on February 7, 2005 ORA and UCAN filed comments. SDG&E served an errata, Ex. SDG&E-10 on February 4, 2005 and it was received into evidence. The matter was submitted on February 9, 2005. This decision adopts rates consistent with Ex. SDG&E-9 and SDG&E-10 as modified for the reasonableness adjustments to the recorded costs.

4. The Burden of Proof

SDG&E and ORA did not discuss the burden of proof in opening briefs. In its opening brief, UCAN argues that SDG&E bears the burden of proof to "demonstrate the reasonableness of its application, SDG&E must support each component of its proposed request through clear and convincing evidence."[11] UCAN correctly states the law, as applied in this decision. SDG&E must meet its burden of proof and demonstrate that in fact its responses to the 2003 Wildfires were prudent and consistent with the Commission's standard for prudent managerial action. Finally, it is the utility, not the staff or interested parties that faces the burden of showing with clear and convincing evidence that its course of action was reasonable and therefore entitled to compensation. As discussed below we find that in this proceeding SDG&E has met its burden.

a. The Standard for Prudent Managerial Action

The Commission's standard[12] in a reasonableness review of managerial action is settled. In a reasonableness review of the 2003 Wildfires, and consistent with previous statements of the standard, SDG&E should be held to the following standard:

> Utilities are held to a standard of reasonableness based upon the facts that are known or should be known at the time. While this reasonableness standard can be clarified through the adoption of guidelines, the utilities should be aware that guidelines are only advisory in nature and do not relieve the utility of its burden to show that its actions were reasonable in light of circumstances existent at the time. Whatever guidelines are in place, the utility always will be required to

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11 UCAN Opening Brief, p. 9, citing D.01-10-031 Ordering Paragraph 26.

12 Decision 02-08-064 (2002 Cal. PUC LEXIS 534; 219 P.U.R.4th 421).

> demonstrate that its actions are reasonable through clear and convincing evidence.[13]

Thus, the reasonableness of a particular management action depends on what the utility knew or should have known at the time that the managerial decision was made, not how the decision holds up in light of future developments. The Commission has affirmed this standard of review in numerous decisions over many years.

The term "reasonable and prudent" means that at a particular time any of the practices, methods, and acts engaged in by a utility follows the exercise of reasonable judgment in light of facts known or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices. Good utility practices are based upon cost effectiveness, reliability, safety, and expedition.

> 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.[14]

The 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:

> Thus, a decision may be found to be reasonable and prudent if the utility shows that its decision making process was sound,

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13 D.88-03-036 (1988 Cal. PUC LEXIS 155,*7; 27 CPUC2d 525).

14 D.87-06-021 (1987 Cal. PUC LEXIS 588, *28-29, 24 CPUC 2d 476).

> 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. As we have previously stated, the action selected should logically be expected, at the time the decision is made, to accomplish the desired result at the lowest reasonable cost consistent with good utility practices.[15]

The Commission has noted that this standard can prove difficult to apply:

> The reasonable and prudent act is not limited to the optimum act, but includes a spectrum of possible acts consistent with the utility system need, the interest of the ratepayers, and the requirements of governmental agencies of competent jurisdiction.[16]

And:

> The burden rests heavily upon a utility to prove with clear and convincing evidence, that it is entitled to the requested rate relief and not upon the Commission, its staff, or any interested party to prove the contrary.[17]

Thus, although the utility need not show that it has undertaken the optimal act, it must show that its course of action was reasonable and that the utility took care in making its decision.

5. Review by Other Parties

UCAN proposes in its opening brief a standard of review that would preclude SDG&E from recovery of costs subject to the CEMA tariff provisions

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[15] D.89-02-074 (1989 Cal. PUC LEXIS 128, *11, 31 CPUC 2d, 236).

[16] *D.90-09-088 (1990 Cal. PUC LEXIS, 847*, *23-25, *37 CPUC 2d 488, 499)*, based on language in D.87-06-021, and quoted with approval in *D.98-09-040 (1998 Cal. PUC LEXIS 972* *34-35).

[17] *Ibid.*

unless ORA performed a review sufficient to meet the standards as asserted by UCAN. This argument would shift the burden of proof to ORA – it would unreasonably shift to ORA the Commission's obligation to determine whether a utility behaved in a reasonable fashion. Neither UCAN nor ORA are obliged to review an application by SDG&E before the Commission can make a finding on reasonableness: their appearance often informs the proceeding; but it is not a precondition for the Commission to reach a decision.

UCAN relies on a decision rejecting a settlement where ORA assumed the burden of a settling party[18] to show that the settlement was fair. Our standard for a settlement is established in Rule 51.1(e) that requires it to be "reasonable in light of the whole record, consistent with law, and in the public interest." The Commission found in D.01-02-075 that ORA had not performed sufficient analysis, so as to have an adequate and informed opinion, necessary to settle with SoCalGas.

UCAN's interpretation of D.01-02-075 would tie the hands of the Commission giving ORA a virtual veto over any rate recovery. If ORA did not participate, logically according to UCAN, we could not find the applicant's request to be reasonable. As noted previously, this is not the case.

6. Restoration Management

This section addresses the reasonableness of the overall management response to the Wildfires.

SDG&E presented testimony describing its response to the Wildfires, beginning with monitoring and rapidly progressing to activation of an

[18] D.01-02-075, Conclusion of Law No. 1: "The burden of proving that the settlement is fair is on the proponents."

"emergency desk" and finally the activation of SDG&E's Emergency Operations Center.[19] Ultimately SDG&E decided to call for assistance on other utilities, Arizona Public Service Company, Pacific Gas and Electric Company, Sacramento Municipal Utility District, Sierra Pacific Power Company, Tucson Electric Power, the Salt River Project, and the Western Area Power Authority. All of them were reimbursed by SDG&E and the costs are included in the Wildfire Account. Southern California Edison Company was at risk from the fires and was not called on for assistance. The use of mutual assistance crews and additional contractor personnel was necessary to restore service in a timely fashion.

Senior management was involved in the oversight of the project and SDG&E systematically (to the extent possible following the fires) tried to reestablish service as quickly as possible. As a result, the company had to quickly assess the damage and plan a coordinated response. We find that SDG&E has met its burden of proof to show that it actively engaged in a reasonable response directed and supervised by senior management in a coordinated manner. SDG&E used a central management process that gave it the best opportunity to respond to the Wildfires in a rational and responsible fashion with the information that was available during the project. The use of the Emergency Response Center, and the operational decisions described in the testimony and in this record, meet the prudent manager standard.

7. Reasonableness of Costs

This section addresses SDG&E's prudence in controlling and reasonably managing the costs incurred to restore service following the 2003 Wildfires. Before we can consider the reasonableness of the proposed allocation of costs to

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[19] Ex. SDG&E-1, pp. 2-3.

retail customers we must first examine the total costs incurred, consider any available revenues to offset to these costs to determine the incremental costs, and then determine the appropriate allocation of incremental costs.

SDG&E stated that it had no insurance coverage that would reimburse the costs of the Wildfires. The justification is the cost of insurance estimated at $3 million annually for $10 million in coverage.[20] Thus in about two years the premiums would have equaled the coverage provided for the Wildfires. Based on this explanation it is reasonable not to expect insurance coverage for these costs.

SDG&E used an "incremental cost criteria" to calculate costs includable in the Wildfire Account. That is, the company assumed direct labor at straight - time (excluding overtime) and other costs that were incurred solely to restore service are incremental to existing costs already included in rates. SDG&E stated its belief that this approach is in conformance with Resolution E-3238. ORA concludes that SDG&E's calculations of incremental costs are a reasonable basis for recovering the Wildfire Account. ORA further supports the recovery of the incremental costs either through the amortization of the expenses included in the Wildfire Account and the capital expenditures added to SDG&E's rate base, as calculated by SDG&E.[21] UCAN notes various adjustments and proposes several specific disallowances, and in addition to those issues which are discussed below, UCAN otherwise opposes the rate recovery of the Wildfire Account costs based on its burden of proof arguments.

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[20] Ex. SDG&E-3, p. 15.

[21] Ex. ORA-1, pp. 2-4, 3-3, 4-3, 6-3, 7-2, and 8-2.

We find that, except for one exception as noted in the following section, SDG&E has accounted for its costs in a reasonable manner and it is reasonable to allow rate recovery of the Wildfire Account costs.

a. ORA's Examination

ORA's prepared testimony in Ex. ORA-1 indicates that its staff conducted a review of the costs incurred to restore service and found only the one exception noted in its testimony. Otherwise, ORA believes the incremental costs to be reasonable.[22] The one cost recovery exception noted by ORA is to exclude from recovery $9,146 for advertisements used to publicly thank the other utilities that provided mutual assistance to SDG&E.[23] We will adopt this minor adjustment, with which SDG&E has agreed.

b. UCAN's Recommendations

UCAN submitted prepared testimony in Ex. 151, which makes several recommendations:

1. Disallow $738,400 for food-related costs that cannot be justified. (p. 6.)
2. An estimated $42,348 in pole test and treat expenses avoided over the next 4 years should be offset against the Wildfire Account O&M expense. (p. 7.)
3. Prior to evidentiary hearings, UCAN was concerned that SDG&E used an incorrect franchise fee and uncollectible allowance for an error of $67,000. (p. 10.)
4. UCAN expresses a non-monetary concern that SDG&E's tree-trimming inventory has increased, rather than decreased in the fire-damaged area. (p. 8.)

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[22] Ex. ORA-1, pp. 1-4 and 1-5.

[23] Ex. ORA-1, p. 7-2.

5. SDG&E incorrectly accounts for $7.2 million in various Support Services as an expense, which should be allocated between expense and capital (rate base) based on the relative split of direct labor - 15.8% to expense and 84.2% to capital. (p. 9.)
6. Because of the rate impact of SDG&E's Cost of Service A.02-12-028 (2004 increase under collection plus 2005 attrition increase.) the Commission should amortize the Wildfire Account over two years instead of one. (pp. 10-11.)

UCAN applies an additional reasonableness test to SDG&E's request that was not employed by ORA. UCAN argues that some of SDG&E's costs are excessive when compared to a fair market price for the commodity.[24] UCAN does not dispute that SDG&E incurred the costs nor does it disagree with SDG&E's process for allocating costs to the Wildfire Account. It does take exception to the ratemaking treatment of certain costs. UCAN in total considered cost causation, cost reduction and cost avoidance as a part of its examination of SDG&E's proposals.

1. Food Services

The company spent $5.4 million to provide meals, snacks, water and other items, and over 92,000 meals. UCAN could not determine the accuracy of the 92,000 meal count. UCAN disputes the total based upon the duration of the project and the number of personnel involved. UCAN first equates the total to 30,677 person-days of meals, assuming 3 meals per day. Next, UCAN argues that the personnel counts provided by SDG&E in testimony and data responses total only 1,339 and not 1,800 as stated by the company in Ex. 2 and this suggests

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[24] This would equate to the "cost reduction" standard included in D.01-02-075.

5,400 meals a day not the 6000 included in Ex. 2.[25] UCAN expresses a very significant concern with SDG&E's contract management practices and concludes that SDG&E did not exercise sufficient reasonable control over costs or the performance of some vendors.

UCAN closely examined the snack and drink cost of approximately $2 million and took exception to the costs incurred for Gatorade, bottled water and Red Bull energy drink. UCAN opined that SDG&E paid its vendors a significant premium compared to the nearby COSTCO in La Mesa, California, and based on a daily consumption calculation, determined that SDG&E was over-charged by $582,300.[26] UCAN argued that employees appeared to consume extraordinary quantities and that SDG&E exercised no reasonable control over unit costs. UCAN justifies the disallowance by showing that the other costs included in a typical retail price are already separately charged to the Wildfire Account as ancillary costs and labor. UCAN also argued in its opening brief that food services costs should be further reduced by $113,111[27] based on its calculation of extra (*i.e.*, unnecessary) meals.

SDG&E's rebuttal testimony objects to UCAN's price comparison and argues that it "did not have the luxury of time or resources to evaluate all options ahead of time, plan out exactly what was needed and then competitively

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[25] Ex. 151, pp. 2-3, compared to data in Ex. 2, p. 30.

[26] UCAN adds 7.75% for sales tax and then deducts a 10% discount from the total. UCAN initially calculated an adjustment of $738,400, corrected at hearing by the witness.

[27] UCAN Opening Brief, p. 7, and shown in detail in footnotes 63 and 64 on p. 23.

bid for these emergency services and supplies." SDG&E argues too that it was against company practices for employees to make purchases on behalf of SDG&E[28] without going through established processes"[29] SDG&E also argues that UCAN made a simplistic count of meals without considering such things as some tired and hungry employees (Ex. 4) ate more than a single portion, there was no "rationing," the incidental feeding of police, fireman and even fire victims, and overall, UCAN did not consider the complexity of the project to quickly restore service after the wildfires. The company concludes that it "followed its procedures and generally accepted practices and utilized established catering firms that it believed could meet the challenge during this extraordinary time. The unit prices for meals, snacks and drinks were in line with typical rates utilized by the catering industry."[30]

UCAN proposes to apply a further appropriate test to the costs that is more rigorous than the ORA tests discussed above. UCAN argues that SDG&E unreasonably paid excessive prices that were charged by the food service vendors for the basic commodities of bottled water and various energy drinks by failing to exercise reasonable control over the contractors or its own employees.

Discussion

The essential question is whether SDG&E exercised sufficient control over its vendors to ensure that despite the desperate situation of the Wildfires it paid reasonable prices for essentially basic commodities: bottled water, energy drinks,

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[28] UCAN does not say SDG&E should have done "snack-runs" to COSTCO, only that SDG&E was charged too much by the vendors it used for food services.

[29] Ex. 4, pp. 2-3.

[30] Ex. 4, p. 8.

and snacks. We believe that it did, and we reject UCAN's arguments to the contrary. As ORA argued in its Reply Brief:

> Over the course of almost a month, SDG&E and its Mutual Assistance and Contract crews worked around the clock in extremely hazardous conditions and often in inaccessible areas to restore utility service. The suggestion that SDG&E should have diverted resources to comparison shopping for Gatorade does not strike ORA as either [sic] responsible, reasonable, or a productive use of limited resources.[31]

We agree, and therefore decline to make the disallowances. Furthermore, comparing the prices paid by SDG&E for drinks for its workers to prices at a local Costco is not appropriate for weighing whether SDG&E met its burden of proof for cost control purposes as it fails to create a consistent comparison.

2. Avoided Pole Test and Treat Expenses

UCAN determined that SDG&E replaced 2,872 poles used for distribution service, and that 73% of the destroyed poles (2,096) were over 15 years old which put them on a 10-year inspection and treatment cycle. UCAN believes that no inspection will be needed on the new poles during the next 10 years and this will avoid inspections at $34.29 per pole.[32] UCAN allows for the 30% of 2,096 older poles (861) that were already inspected before they were destroyed by the fire so SDG&E only avoids inspecting the remaining 70% or 1,235 poles that were

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[31] ORA Reply Brief, p. 5.

[32] Ex. 151, p. 6, *see* also UCAN DR 3, Q 15, and DR 3, Q 18.

destroyed before inspection. Savings calculated by UCAN total $42,348.[33] UCAN proposes to offset this amount from the Wildfire Account and avoid the complication of adjusting base rates to reduce the number of pole inspections forecast in base margin rates.

SDG&E responds that an offset is unreasonable because under conventional cost of service ratemaking "practices do not require the utility to expend every dollar of its authorized revenue requirement as the utility may have predicted would be necessary in its cost of service application. To the contrary, traditional test year ratemaking principles permit the utility to redeploy its authorized revenue requirement in order to accommodate the real world circumstances it encounters during the test period."[34] SDG&E argues further that money "saved from avoiding inspections of the recently replaced poles, if not needed for inspection and treatment of other poles, will most likely be spent on other reliability-related activities."[35]

Discussion

The narrow scope of the CEMA proceeding is limited to addressing the recoverability of costs incurred in response to the catastrophic event. UCAN's proposed reduction exceeds this narrow scope and ignores traditional ratemaking principles. UCAN's analysis fails to acknowledge that any money saved from avoided inspections of replaced poles will likely be spent on other reliability-related activities. Consistent with traditional ratemaking principles, SDG&E may redeploy its authorized revenue requirement in order to

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33 Ex. 151, pp. 6-7. (1,235 poles @ $34.29 = $42,348.)

34 Ex. 5 p. 2. (Rebuttal.)

35 Ex. 5, p. 2.,

accommodate the real world circumstances it encounters during the test period. The implications of these redeployments are then assessed in a subsequent Cost of Service proceeding or, if appropriate, by means of an authorized earnings sharing mechanism. We are persuaded by SDG&E's arguments and reject UCAN's proposed disallowance.

3. Franchise Fees and Uncollectibles

SDG&E requests $627,000 for <u>both</u> franchise fees and otherwise uncollectible revenue (billed to customers but never collected).[36] Initially UCAN identified what it believed to be a computational error of $7,000 for Franchise Fees and Uncollectibles. SDG&E testified that the correct calculation is to increase the recoverable costs ($15,300,000) by a factor that recovers both the uncollectible allowance and the appropriate franchise fees. This is a typical ratemaking convention to ensure the utility an opportunity to recover the full amount of authorized revenues. The calculation has to allow for a full recovery including collecting from all customers the amount otherwise uncollectible from a few, plus the franchise fees SDG&E must pay on the total. SDG&E calculates[37] the gross-up factor as: 1 / 1 – (3.67% + 0.266%) = 1.041. The revenue requirement request after "grossed-up" is $15,300,000 x 1.041 = $15,927,000.

Discussion

UCAN withdrew its testimony without further explanation following SDG&E's rebuttal.[38] After reviewing SDG&E's calculation we agree that it has

[36] Ex. 3, attached Exhibit D-4. (SDG&E captioned attachments to testimony as "exhibits," thus Ex. 3 contains attachments also titled as exhibits.)

[37] Ex. 5, p. 6.

[38] Transcript, p. 115, deleting *Section B. Franchise Fees and Uncollectibles*, in Ex. UCAN-1 at p. 10.

made the correct calculation for recovery of the franchise fee and otherwise uncollectible revenues. We will use this method as a part of the calculation of the final revenue requirement authorized in this decision.

4. Tree Inventory

UCAN argues that SDG&E has been removing large numbers of trees as a result not only of the Wildfires but also due to the bark beetle infestation that killed many trees and led to a programmatic removal of affected trees. UCAN points out that a tree inventory before October 6, 2003, *i.e.*, prior to the Wildfires, showed 145,575 trees. A September 2004 inventory showed 145,661 trees, an increase of 86 trees. UCAN is concerned that after the removal of numerous trees due to the Wildfires and the bark beetle, the inventory tally should have clearly fallen, and that SDG&E needs to explain this anomaly.

SDG&E explains in rebuttal that many scorched trees are retained in the inventory until they determined whether or not the tree will survive. Additionally, SDG&E added scorched trees outside the rights-of-way and not in the previous inventory because they may fail and could subsequently fall into the overhead lines.

SDG&E's explanation is reasonable and no further action is necessary at this time.

8. Ratemaking Treatment

This section addresses the reasonableness of the ratemaking proposal to recover the reasonable costs of the 2003 Wildfires. Included in this section are two of UCAN's proposals.

a. Allocation of Support Costs to Expense and Capital

UCAN argues that SDG&E inappropriately categorized various support costs totaling about $7.2 million as expense rather than allocating the costs between expense and capital expenditures includable in rate base. UCAN uses an allocation factor of labor costs and calculates that 15.8% should be expensed and 84.2% should be capitalized.[39] According to UCAN, SDG&E used the too literal assumption that meals and lodging are consumed and should be expensed. UCAN objects to SDG&E's accounting interpretation that environmental support costs ($1.2 million of the total) were not incurred as a part of new construction. UCAN also argues that some environmental costs were clearly for pole replacement and reconductoring projects, but for simplicity it did not compute a separate environmental allocation. UCAN proposes to allocate these costs in proportion to direct labor. The effect of UCAN's recommendations is to allocate a larger share of the support costs to capital which results in rate recovery through depreciation over a longer period of time.

SDG&E's proposes to expense these overheads because these costs were "consumed" concurrently[40] and should not be capitalized as a part of the costs of installing new long-lived assets. SDG&E did not capitalize these costs because as a general rule, they argue that costs with future economic value or alternative uses should be capitalized.[41] SDG&E's witness testified that this approach is generally consistent with GAAP, the Code of Federal Regulations and SDG&E's current accounting practices, and is supported by ORA.[42]

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[39] Ex. 151, pp. 8-9, relied on Ex. 4, Exhibit G-9, G-12 and H-13 for the support costs, and Ex. 3, Exhibit D-1 for the labor costs to calculate the split.

[40] Ex. SDG&E-4, p. CAS-3, lines 10-18.

[41] Ex. SDG&E-6, p. 3.

[42] Ex. SDG&E-6, p. 3-5; Bower/ORA, Tr. 146-148.

SDG&E does not agree with UCAN's proposal to capitalize more of these costs rather than expensing them. SDG&E argues that the record shows that not only would this approach be inconsistent with established practices, it would not be in the best interests of customers to unnecessarily extend the recovery of these expenses for 30-40 years while SDG&E earns a return on these consumable, non-construction costs.[43]

Discussion

Our well-established ratemaking practice is consistent with the matching principle or concept in accounting. That principle requires costs incurred for current service to be "expensed" in a single year and all of those costs that are necessary to provide service over many years to be "capitalized" and recovered over the useful life of the underlying asset. In this proceeding, many physical assets, poles, wire, transformers, etc., that were destroyed by the Wildfires were capitalized when they were originally placed in service.

The overhead costs at issue in this proceeding include the crew support costs that were incurred to provide food and shelter to the crews during the firestorm restoration efforts. SDG&E has applied its general rule that since these expenses do not have a future economic value or an alternative use, they should not capitalized. Moreover, SDG&E argues that these costs were not project-specific or incidental; they were part of a greater effort to restore service to those customers in SDG&E's service territory who were victims of this extraordinary and tragic event. As discussed under the management of the project, we found SDG&E to be reasonable in its many decisions, big and small, on how to

[43] Ex. SDG&E-6, p. 5.

reasonably restore service. While it can be argued that this finding does not automatically extend to the ratemaking consequences, we give it great weight in our consideration in this instance

We agree with SDG&E's interpretation to expense all support costs, including meals and accommodations. If SDG&E were to capitalize these costs as UCAN suggests, the incremental CPUC-jurisdictional capital expenditures attributable to the firestorms would increase by approximately 25%, resulting in overvalued assets without any real increase in their use value or life

With respect to the environmental costs, UCAN argues that SDG&E failed to allocate appropriate environmental support costs to capital projects. The record shows that SDG&E recorded $1.320 million in environmental costs to operating and maintenance expense and only $0.003 million to capital. SDG&E only capitalized $3,000 for environmental costs out of the total $25,605,000 that is capitalized by SDG&E.[44] The environmental services costs incurred in connection with the firestorm were primarily for operational erosion control assessments and hazardous material clean up, as well as for equipment and supplies required to determine the firestorm natural resource damages. UCAN suggests using the labor cost allocation as a proxy to allocate the environmental costs. We agree that SDG&E's allocation of all support costs, including environmental costs, almost exclusively to operating and maintenance expense reflects a reasonable allocation of costs between expense and capital.

UCAN's ostensible enthusiasm for capitalizing these support costs appears to be motivated by a desire to reduce the short-term impact on customers' rates

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[44] Ex. SDG&E-4, attached Exhibit J, pp. 1 through 3. Incremental environmental costs as included by SDG&E in the Wildfires Account.

by requiring SDG&E to collect these costs over a much longer period. UCAN is shortsighted in this regard, however, and ignores the long-term costs of such an approach. Since these support costs have no future economic value, it is simply not in the interests of ratepayers to extend the recovery of these expenses while SDG&E would earn a return on consumable, non-construction costs over the life of the capital assets replaced during the firestorm (30–40 years). As a matter of general principle, while reducing rates now may lead to immediate rate reductions, the public interest is served by taking a longer term view. Capitalizing more current costs adds to rate base for future recovery and is more costly.

b. Amortization of the Wildfire Account

SDG&E requests a 12-month amortization for the expense portion of the Wildfire Account beginning January 1, 2005. UCAN proposes that the amortization should be doubled to 2 years, citing the impact of rate changes likely in A.02-12-028 for a test year 2004 as well as any attrition allowance for 2005. There are other likely rate impacts too.[45]

Discussion

In fact this decision will not be implemented in time to begin amortization on January 1, 2005. A reasonable compromise is readily available to us to begin amortization on October 1, 2005 for 18 months through December 31, 2006. This will conveniently allow amortization to begin shortly after this decision is

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[45] SDG&E noted in the evidentiary hearing that in another proceeding there is a proposal to substantially increase SDG&E's allocation of costs for energy contracts held by the Department of Water Resources.

adopted and its end will coincide with the next base margin adjustment likely to occur on January 1, 2007.[46]

9. Labor Costs and Incentive Compensation

SDG&E incurred labor costs of $10.076 million to restore services after the Wildfires. ORA performed test procedures and in its opinion verified that this expenditure is supported by payroll records and was credibly incurred. ORA's testimony notes no exceptions to SDG&E's labor costs.[47]

SDG&E made the assumption that all "straight-time" cost of employee labor was not an incremental cost: it was essentially already included in rates, available to restore service, and therefore was not includable in the Wildfire Account. We agree with SDG&E that this is a reasonable convention for catastrophic event cost recovery. SDG&E identifies $726,000 of "time-and-a-half" and $5,581,000 of "double-time" labor costs as both incremental and allocable to California-jurisdictional gas and electric service, because these costs were incurred solely due to the Wildfires.

In addition to the direct costs of $10.076 million for labor, SDG&E also recorded $726,000 for incentive compensation, and allocated $470,000 as incremental costs to be recovered in the Wildfire Account.[48]

Labor	Cost	Incentive	Percent
Union	$8,209,536	$380,838	4.64%

[46] *See* D.04-12-015, p. 10 orders an application for test year 2004. Phase 2 is pending on A.02-12-028 addressing post-test year 2004 ratemaking. Annual adjustments have been consistently allowed in the past.

[47] Ex. ORA-1, p. 3-4, and Transcript, pp. 130-131.

[48] Ex. SDG&E-4, attached Exhibit J, p. 3.

Non-Union & Non-Management	269,579	44,724	16.59%
Cash Awards & Other	15,000	0	-
Management	1,583,304	300,881	19.00%
Total	**$10,077,422**	**$726,443**	

Discussion

We find that SDG&E has justified its request to recover both the direct and incentive labor costs in the Wildfire Account.

10. SDG&E's Wildfires Update

When SDG&E filed A.04-06-035, $66.4 million had already been recorded to SDG&E's Wildfires Account through May 31, 2004. As updated in Ex. SDG&E-9,[49] SDG&E's actual total firestorm costs recorded through December 31, 2004 are $70.6 million, representing a difference of $4.2 million from May 31, 2004. According to SDG&E, the difference is the result of approximately $0.2 million of O&M (primarily environmental costs and accounting adjustments) and $4.0 million of capital expenditures primarily incurred for the rebuilding of Circuit 79[50] and the smaller amount spent on Circuit 176 that serves the eastern area of the city of Poway.

$2.9 million of the additional costs recorded through December 31, 2004 are incremental Commission jurisdictional costs, and according to SDG&E, the balance of $1.3 million is non-incremental and should be excluded from the Wildfires Account. The capital costs were not included when the application

[49] Filed on January 18, 2005.

[50] "Circuit 79 is a 12 kV electric distribution line that traverses through Cuyamaca Rancho State Park. Circuit 79 was extensively damaged during the firestorm and as a result had to be rebuilt and relocated." (Ex. SDG&E-9. p. 1-2.)

was filed because SDG&E records the costs in the Wildfires Account after the work is completed.[51]

On February 4, 2005, SDG&E filed Ex. SDG&E-10, which as errata to Ex. SDG&E-9, made several adjustments to the update. As updated[52] in Ex. SDG&E-10, SDG&E's actual total firestorm costs recorded through December 31, 2004 are $71.1 million, representing an increase of $4.7 million ($71.1 million less $66.4 million) from May 31, 2004. Thus the errata, Ex. SDG&E-10, increased the total by $500,000 compared to the Late-filed Update Ex. SDG&E-9 ($71.1 million less $70.6 million).

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[51] Ex. SDG&E-9. p. 1.

[52] Ex. SDG&E-10, p 2.

Wildfire Costs Including Update & Errata

			CPUC		
	Total Cost	(FERC) Electric Transmission	Electric Distribution	Gas	Total CPUC
O&M Expenses:					
Pre-Update O&M	$ 18,032	$ 1,569	$ 15,865	$ 598	$ 16,463
Internal Labor	$ 11	1	$ 10	$ -	$ 10
Materials	4	(1)	5	-	5
Overhead	10	1	9	-	9
Vehicle Charges	(2)	-	(2)	-	(2)
External Labor	8	-	8	-	8
Services/Other	225	16	$ 208	1	209
Update & Errata	$ 256	$ 17	$ 238	1	239
Total O&M	$ 18,288	$ 1,586	$ 16,103	$ 599	$ 16,702
Capital Costs:					
Pre-Update Capital	$ 48,395	$ 6,847	$ 41,445	$ 103	$ 41,548
Internal Labor	$ 47	-	$ 41	$6	47
Materials	19	-	17	2	19
Overhead	1,229	2	1,213	14	1,227
Vehicle Charges	30	-	29	1	30
External Labor	342	-	342	-	342
Services/Other	2,813	6	2,807	-	2,807
Update & Errata	4,480	8	4,449	23	4,472
Total Capital	$52,875	$ 6,855	$ 45,894	$ 126	$46,020
Updated Total	$ 71,163	$ 8,441	$ 61,997	$ 725	$ 62,722

According to SDG&E, the final difference is the result of approximately $0.3 million of O&M (primarily environmental costs and accounting adjustments) and $4.4 million of capital expenditures primarily incurred for the rebuilding of Circuit 79[53] and the smaller amount spent on Circuit 176 that serves the eastern area of the city of Poway. As revised, $3.2 million of the additional costs recorded through December 31, 2004 are incremental Commission jurisdictional costs, and according to SDG&E, the balance of $1.5 million is non-incremental and should be excluded from the Wildfires Account.

Memo Account-Eligible Wildfire Costs
Including Update & Errata

	Total (CPUC) (a)	Memo Account (b)	Current Rates (b)
Pre-Update O&M	$ 16,463	$ 12,056	$ 4,407
Internal Labor	$ 10	-	$ 10
Materials	5	-	5
Overhead	9	44	(35)
Vehicle Charges	(2)	-	(2)
External Labor	8	-	8
Services/Other	209	(17)	226
Update & Errata	$ 239	$ 27	$ 212
Total O&M	$ 16,702	$ 12,083	$ 4,619
Capital Costs:			
Pre-Update Capital	$ 41,548	$ 25,605	$15,943
Internal Labor	$ 47	5	42
Materials	19	19	-
Overhead	1,227	5	1,222
Vehicle Charges	30	-	30
External Labor	342	342	-
Services/Other	2,807	2,745	$62
Update & Errata	$ 4,472	$ 3,116	$ 1,356
Total Capital	$ 46,020	$ 28,721	$ 17,237
Total Wildfire	$ 62,722	$ 40,804	$ 21,919

(a) Ex. SDG&E-10, attached Ex. D-1.
(b) Ex. SDG&E-10, attached Ex. D-2.

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53 "Circuit 79 is a 12 kV electric distribution line that traverses through Cuyamaca Rancho State Park. Circuit 79 was extensively damaged during the firestorm and as a result had to be rebuilt and relocated." (Ex. SDG&E-9. p. 1-2.)

On February 9, 2004, ORA and UCAN filed comments on SDG&E's updated testimony and errata. ORA had no objections. UCAN was succinct: it questioned the late inclusion of $600,000 of costs incurred prior to May 31, 2004; and secondly, UCAN pointed out that the update and errata include $209,000 of environmental costs which it believes supports UCAN's contention that the environmental costs are connected with the cost of installation of a capital project and should be capitalized.[54] UCAN does not convince us that SDG&E's earlier omission is somehow unrecoverable when included in an update. We know from SDG&E's testimony and ORA's review that SDG&E established reasonable accounting procedures to segregate and track the Wildfire costs. Corrections and updates are not innately unreasonable. We will not make this adjustment.

11. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Opening Comments were filed by SDG&E and UCAN on August 8, 2005. Reply comments were filed by UCAN and SDG&E on August 15, 2005. The comments are incorporated herein.

12. Assignment of Proceeding

Susan P. Kennedy is the Assigned Commissioner and Douglas M. Long is the assigned Administrative Law Judge and principal hearing officer in this proceeding.

Findings of Fact

1. As a result of massive wildfires, on October 26, 2003, then-Governor Davis declared a state of emergency for San Diego County. The following day,

[54] UCAN comments, p. 3.

October 27, 2003, President Bush also declared a state of emergency for San Diego County.

2. Approximately 3,200 power poles, 400 miles of wire, 400 transformers and more than 100 other pieces of related equipment were damaged by the fire and needed to be replaced by SDG&E. In total, SDG&E spent $71.1 million to replace lost equipment and restore service.

3. SDG&E's actions were reasonable when it activated its Emergency Operations Center. As a result of the damage, SDG&E decided it was necessary to call on other utilities for assistance to restore service. The use of mutual assistance crews and additional contractor personnel was necessary to restore service in a timely fashion. Senior management was involved in the oversight of the project and SDG&E systematically tried to reestablish service as quickly as possible.

4. Based on the high cost of premiums and limits on coverage, SDG&E had no reasonable insurance option to offset the costs of the Wildfires.

5. Resolution E-3238 established the Commission's requirements for invoking and applying the CEMA tariff provisions. SDG&E complied with these requirements by informing the Commission in a timely manner and establishing separate accounting and other controls for the Wildfires' costs. The company reasonably assumed that direct labor at straight -time (*i.e.*, excluding overtime) was not includable in the Wildfire Account, but overtime labor and other costs incurred solely to restore service are incremental to existing costs already included in rates.

6. ORA's examination of SDG&E's actions was focused on ensuring that only incremental costs were included in the Wildfire Account. ORA found that SDG&E included in the Wildfire Account $9,416 for newspaper advertisements

to thank the utilities that provided mutual assistance crews. This cost was not necessary to restore service and is not reasonably included in the Wildfire Account.

7. ORA did not review the reasonableness of expenditures for a cost causation perspective or from a cost reduction or avoidance perspective.

8. UCAN applied an additional reasonableness test to SDG&E's request. UCAN proposed that costs incurred by SDG&E should be compared to a fair market price for the commodity.

9. SDG&E provided meals, beverages and snacks in large number to all workers, including, incidentally, some police, fire and other workers involved in fighting the Wildfires or SDG&E's efforts to restore services. SDG&E utilized established catering firms that it believed could provide adequate service in numerous locations throughout the affected service territory.

10. SDG&E's vendors charged for food service on the basis of the number of meals served, but the measurement was a standard assumption of the size of food portions that would constitute a meal. Many workers often ate the caterer's equivalent of multiple meals as a result of long hours and hard work. No accurate head-count was maintained. SDG&E did negotiate a generic 10% reduction to the bills from one major vendor after the Wildfires.

11. SDG&E exercised reasonable control over all vendor costs, including the costs of meals, snacks and drinks.

12. The CEMA process as authorized in Resolution E-3238 allows SDG&E the opportunity to recover its reasonable costs incurred as a result of a catastrophic event. Without this ratemaking exception, SDG&E would have no option but absorb all of its Wildfires expenses and would only recover capital expense

changes to rate base in a subsequent rate setting proceeding such as the next general rate case.

13. In order to allow for a full cost recovery, Commission ratemaking conventions allow SDG&E to increase its revenue requirement to collect from all customers the amount of revenue otherwise uncollectible from a few, plus the franchise fees it pays on the total revenue requirement. SDG&E correctly calculated the gross-up factor as: 1 / 1 – (3.67% + 0.266%) = 1.041.

14. The tree inventory maintained for vegetation management has increased since the Wildfires because damaged trees adjacent to the right-of-way are now monitored by SDG&E. Many damaged trees in the right-of-way were not physically removed and remain in the inventory.

15. The total cost of replacing long-lived assets destroyed by the Wildfires is higher because SDG&E expedited construction; this management decision resulted in incurring both higher costs, including overtime and mutual assistance, and additional costs, including meals and snacks, compared to slower methods of restoring service. All of the costs are allocated between maintenance, which is a current expense, and capital expenditures, which reflect installing long-lived assets in rate base.

16. SDG&E expensed most of its support costs that are accounted for as overheads based on its interpretation of the applicable accounting standards that these costs were immediately "consumed" and should not be capitalized as a part of the costs of installing new long-lived assets in rate base as they have no future economic value or alternative use.

17. UCAN recommended an allocation factor for support costs based on the allocation of labor costs to reflect the correct split of costs between expense and

capital. This method allocates 15.8% to current expense and 84.2% to capital expenditures.

18. SDG&E correctly allocates its crew support costs to expense.

19. SDG&E employees are eligible for incentive compensation under a performance evaluation plan where the actual incentive is based upon their performance in relationship to specific goals and objectives. SDG&E accrued $726,000 for incentive compensation, and allocated $470,000 as incremental costs to be recovered in the Wildfire Account. SDG&E demonstrated that these costs are appropriately recovered in the Wildfire Account.

Conclusions of Law

1. The disaster declarations issued by the Governor and the President for the 2003 Wildfires constitute an event declared to be a disaster by competent state or federal authorities for purposes of § 454.9.

2. Use of the Wildfire Account for recording and recovering the costs incurred by SDG&E to restore utility service to customers, repair, replace or restore damaged facilities, as caused by the 2003 Wildfires, is appropriate under the statute as written.

3. SDG&E alone bears the burden of proof to show that its costs were reasonable and are eligible for recovery under the CEMA tariff.

4. The Commission's Standard for Prudent Managerial Action is the appropriate standard to apply to the costs recorded in the Wildfire Account.

5. The Commission is not dependent on an intervenor performing any specific analysis before the Commission may determine the reasonableness of a pending matter.

O R D E R

IT IS ORDERED that:

1. The reasonable total recoverable costs resulting from this Catastrophic Event Memorandum Account (Wildfire Account) application is $40.8 million to be collected in retail rates charged by San Diego (SDG&E).

2. For electric CEMA costs, the non-capital expenditure portion and the 2003-2005 capital-related revenue requirement portion shall be amortized in rates beginning October 1, 2005 and ending December 31, 2006. The 2006-2007 capital-related revenue requirement shall be recovered as an annual adjustment to base margin rates effective January 1 of 2006 and 2007. For gas CEMA costs, the recovery of the approved costs should be handled through a transfer to the Gas Fixed Cost Account as proposed by SDG&E.

3. SDG&E shall file a compliance advice letter with the Commission's Energy Division for its electric department Wildfire costs prior to the effective date of the rate change described in Ordering Paragraph No. 2. It shall be served on the service list for this proceeding. The advice letter shall include the calculations of the rate amortization to recover the current portion of the Wildfire Account and include a description of the recovery in the Preliminary Statement.

4. SDG&E's gas department Wildfire costs shall be recovered by transferring the gas department Wildfire Account balance to the Core and to the Noncore Fixed Cost Accounts. SDG&E shall file an advice letter to allocate the gas department's Wildfire costs between Core and Noncore. The Wildfire costs allocated to the Core and Noncore Fixed Costs Accounts shall be recovered in rates as a part of the ongoing operation of these accounts. The advice letter will be effective on the date filed subject to Energy Division determining that the filings are in compliance with this order.

5. Application 04-06-035 is closed.

This order is effective today.

Dated August 25, 2005, at San Francisco, California.

MICHAEL R. PEEVEY,
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
DIAN M. GRUENEICH
JOHN A. BOHN
Commissioners

ENMAX ENERGY CORPORATION Decision 2006-104
2006 REGULATED RATE TARIFF NON-ENERGY Application No. 1455154

ENMAX Energy Corporation

2006 Regulated Rate Tariff Non-Energy

October 24, 2006

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2006-104: ENMAX Energy Corporation
2006 Regulated Rate Tariff Non-Energy
Application No. 1455154

October 24, 2006

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5 TERMS AND CONDITIONS

EEC stated that for 2006, it had made minor revisions to its Terms and Conditions to make them consistent with the new RRO Regulation, by changing the words "Regulated Rate Tariff" to "Regulated Rate Option Tariff" and changing references from the "Regulated Default Supply Regulation" to "Regulated Rate Option Regulation." EEC stated that the substantive Terms and Conditions remain unchanged. EEC submitted that the minor revisions required by the change in regulation should be approved as applied for.

The CG did not comment on the EEC Terms and Conditions.

The Board has examined the EEC Terms and Conditions by way of Information Requests,[87] and considers that EEC has provided the additional clarification requested by way of its responses to the Board's questions.

The Board notes that EEC amended its Application to remove Application Fees from its Fee Schedules, in order to satisfy section 19(1) of the RRO Regulation. The Board has addressed the revenue requirement impact of this Fee Schedule amendment in Section 4.9 of this Decision. The Board is of the view that a change in the Fee Schedule does not necessarily impact the meaning or intent of the remainder of EEC's Terms and Conditions, nor has any party suggested that a change of the Fee Schedule had any such an impact. Therefore, the Board will not comment any further on this matter.

The Board agrees with EEC that the substantive Terms and Conditions remain unchanged, and that the changes proposed by EEC are simply updates to provide alignment with the wording of the RRO Regulation.

The Board therefore approves EEC's revised Terms and Conditions as submitted on May 19, 2006. For completeness, the Board has included a complete copy of the EEC Terms and Conditions, and Fee Schedules, as Appendix 6 of this Decision.

6 SERVICE QUALITY INCENTIVE MARGIN

In its Application, EEC sought approval for a service quality incentive margin (SQI margin). EEC proposed that it would work together with CCA, PICA and the Utilities Consumer Advocate (UCA) (collectively the Consultation Parties) to develop and file with the EUB service metrics applicable to them as the RRT provider in the distribution area of ENMAX Power Corporation (EPC), with a target date of December 31, 2006. So long as EEC and the Consultation Parties are "using best efforts" to develop the service quality standards and metrics, EEC will be entitled to $0.75/MWh on all energy provided to eligible customers from July 1, 2006 until the earliest of: the date the parties agree on service quality metrics; the date the Board implements standards and incentives under section 22 of the RRO Regulation; and June 30, 2011. EEC also set out some proposed contingency plans coordinating the outcome of the consultation process with the outcome of the Board's implementation process.

[87] BR.EEC-028, BR.EEC-029, BR.EEC-030, BR.EEC-031

According to the proposal, once EEC and the Consultation Parties have agreed on service quality metrics, EEC will have an opportunity to earn up to a maximum of $1.50/MWh on all energy provided to eligible customers during the period from July 1, 2006 to June 30, 2011. EEC's eligibility to earn the SQI margin will be based upon its performance as RRT provider, as measured against certain service quality metrics that parties will use best efforts to develop.

The CG opposed ECC's Application contending that it is simply a means of generating more revenue. In their view, the elements of the EEC proposal ought to be considered later when section 22 of the RRO Regulation is implemented by the Board. The CG stated that EEC is trying to "carve out its own 'implementation' of Section 22 eighteen months in advance…"[88] Further, "[i]n terms of service quality mechanism, [EEC's] proposal is attempting to create the system in a backwards manner. Specifically, ENMAX would be given the money first, with no accountability, and then the system of metrics and targets would be created. The Consultation Parties would have little leverage in negotiations." The CG also presented evidence suggesting that under EEC's proposal, there is a probability that the existing levels of service would be provided at a 30% increased cost, such that "customers would pay more and get nothing in return."[89]

The UCA supported EEC's Application, suggesting that it is preferable to negotiate meaningful quality of service standards and incentives with EEC well before the prescribed January 1, 2008 date. In the UCA's view:

> … [h]aving a willing RRT provider actively involved with customer representatives in the development and implementation of service quality improvement on a defined time schedule has inherent value to eligible customers, rather than forcing the Board and its resources to impose standards and incentives.[90]

The Board notes that section 22 of the RRO Regulation which is the basis for EEC's Application states:

> The Board must determine or establish service quality standards and service quality incentives for providing electricity services under a regulated rate tariff by January 1, 2008.

According to EEC, the Board has the authority to rely on section 22 in the present Application to make a determination on the SQI margin issue prior to January 1, 2008. In its response to BR.EEC-034, EEC stated that:

> …If the Board approves ENMAX's application, ENMAX believes that the Board will have established service quality standards and incentives for providing electricity services under ENMAX's regulated rate tariff, as required by section 22 of the Regulated Rate Option Regulation…

It is clear from the wording of section 22 that the Board was given the mandate to determine and establish service quality standards and incentives. It is also evident that the Board was conferred the power to determine the appropriate Board procedure in which to make such a determination,

[88] Page 15 of Schilberg Evidence
[89] CG Evidence, Schilberg, pp.17-18, and CG Reply, p.3
[90] UCA Argument, p.1

whether it be by way of an application brought by an RRT provider, such as the present EEC Application, or by an industry wide collaborative process, which is already in progress, as will be discussed further below.

In assessing which is the more appropriate Board process to carry out its mandate set out in section 22 of the RRO Regulation, the Board is cognizant of the January 1, 2008 deadline that the Board must adhere to. Since this deadline is two years from the date on which the RRO Regulation came into force, namely December 20, 2005, it is reasonable to infer that the legislature anticipated a very thorough and comprehensive review of the issue by the Board. Thus, while the Board, as argued by EEC, could determine or establish service quality standards and incentives on this Application, in the Board's view, to do so would be premature and would be contrary to the mandate set out in section 22. If the Board is to establish service quality standards and incentives in a meaningful manner, it is reasonable for the Board to require input from all affected parties, including interveners, without the statutory time constraints imposed in this Application.[91] And as already stated the Board has already begun its own implementation process for service quality standards and incentives.

The recent enactment of the RRO Regulation, and in particular, section 22 which entitles RRT providers to a SQI margin was an initiative introduced by the Department of Energy. While section 22 did not come into force until July 1, 2006, the bulk of the RRO Regulation came into force on December 20, 2005. The EUB was aware of the pending January 1, 2008 deadline imposed upon the Board well before section 22 actually came into effect. Staff members of the EUB invited representatives of the electric industry and the UCA to an initial meeting on December 16, 2005, to discuss an implementation process by which the EUB together with the input from industry and interveners could formulate workable service quality standards and incentives.[92] In preparation for that meeting, a straw model[93] was distributed to all parties, which set out a series of potential metrics to measure service quality, as well as issues and considerations arising from those metrics. Only initial discussions took place at that meeting, and no subsequent meetings have been held between the EUB and the various parties, mainly due to the intervention of this Application and its pending outcome.

The Board's implementation process seeks to set standards and incentives uniformly to all RRT providers, unlike EEC's approach which advocates a case-by-case review. Section 22 of the RRO Regulation requires the Board to establish service quality standards and incentives for "providing electricity services". In the Board's view, this language supports a broad approach to establishing appropriate standards and incentives, in that it applies to all RRT providers "providing electricity services". The section does not suggest that the Board ought to make an assessment on a case-by-case basis.

In the Board's view, an industry-wide approach is preferable over a case-by-case approach in that the former is more efficient to administer and results in a more consistent application of the standards and incentives. By providing a consistent application of the standards and incentives, the Board is able to assess the performance of each RRT provider based on a uniform standard and better evaluate one RRT provider's performance against another. Further, from the RRT

91 Section 26(3)(b) of the RRO Regulation requires Board approval of a final RRT by November 1, 2006.

92 Contrary to Schilberg's Evidence (p.14), the Board takes notice that a meeting was in fact held. The CG was not a party to that meeting.

93 Referred to in Schilberg Evidence at p. 14.

provider's perspective, a standardized approach across the industry provides more clarity on what the RRT provider must achieve in order to attain a desired SQI margin.

The straw model that was distributed to the parties and discussed at the December 16, 2005 meeting was based on the service quality measures and metrics contained in Board Directive 003. Directive 003 sets out the standards by which the RRT provider's customer service performance are measured, and requires the RRT provider to monitor and report the results of its performance in these areas. The performance measures and performance monitoring and reporting requirements were developed in consultation with the RRT providers and were established as industry-wide standards. Given the similarity in purposes between section 22 of the RROR and Directive 003, the Board considers that it would be reasonable for the EUB to build upon the existing performance metrics of Directive 003 to establish the service quality standards and incentives required under section 22.

EEC suggested that, even if the Board approved EEC's proposed SQI margin, the EUB could continue with its implementation process under section 22, and that any necessary adjustments would later be made depending on the outcome of the Board's determinations. The Board is concerned that potential inefficiencies might arise with having two concurrent SQI procedures, as it is possible that the EEC process to establish service quality standards with the Consultation Parties could unnecessarily interfere with the EUB's implementation process under section 22. Similarly, EEC's proposal, if implemented, could complicate the EUB's monitoring efforts in that the EUB would need to ensure that EEC complies with its own service quality standards and incentives as well as the requirements set out in Directive 003.

Further, an early Board approval of a SQI margin, without having first determined the foundational metrics for the margin and well before the EUB has had an opportunity to consult with interested parties to determine appropriate service metrics, could unfairly prejudice or advantage a party. For example, EEC could rely upon the metrics that it and the Consultation Parties agree upon as support that their metrics are warranted without other interested parties having had an opportunity for input into the appropriate service quality standards.

The Board generally does not approve the approach proposed by EEC of granting a SQI margin prior to determining the service quality metrics. EEC's approach is, as suggested by the CG, a case of putting the "cart before the horse." The development of the SQI margin is a complex matter involving more than a simple quantification of the appropriate margin. In the Board's view, determination of an appropriate SQI margin would include resolving a number of issues, including: defining the areas of customers' concern; the appropriate metrics or measure to be used to determine service quality; the appropriate scoring system for each metric; and, what the metric will be based on, e.g., number of customers, number of sites or MWh, among other things. These are a few issues that need to be addressed in order for the EUB to meet its mandate under section 22 of the RRO Regulation. EEC has failed to address these issues, suggesting that it does not need to in this Application as the details of the metrics will subsequently be negotiated by the parties. The Board is of the view that acceptance of EEC's figures in a vacuum would be premature and amount to disregard of the mandate imposed upon it under section 22 of the RRO Regulation.

Even if the Board were inclined to accept EEC's approach of granting a SQI margin prior to a determination of service quality metrics, there is insufficient evidence on the record of this Application to render a decision on the appropriateness of the SQI margin proposed by EEC.

EEC submitted that it is entitled to $0.75/MWh until the service metrics are in place. Once they are in place, EEC has the opportunity to receive $1.50/MWh if it meets those service quality metrics,[94] which have not yet been determined by EEC and the Consultation Parties, and possibly, for which an agreement will never be reached. EEC provided no substantial evidence to justify why these figures are appropriate.

Finally, EEC's proposal that it would be entitled to $0.75/MWh for "using best efforts to develop the service quality standards and metrics" appears to lie outside the purpose of section 22 of the RRO Regulation. On the face of it, section 22 is intended to provide an incentive to RRT providers based on their service quality or performance. The $0.75/MWh proposed by EEC is clearly not for performance but an amount awarded simply to use "best efforts" to develop service quality standards and metrics. In the Board's view, it is questionable that EEC is entitled under section 22 to an amount for ordinary and reasonably expected conduct, namely, using best efforts to develop a SQI margin.

For the reasons provided above, EEC's application for a SQI margin is denied. The EUB will continue with its implementation process to determine the appropriate service quality standards and incentives on a broad scale as required by section 22 of the RRO Regulation prior to January 1, 2008.

7 DIRECTIVE 014

In response to EEC's Application, the CG raised issue with the financial reporting requirements of RRT providers in Alberta. In the CG's view, there is an inconsistency in the reporting requirements applicable to "electric utilities" as defined in the EUA and those applicable to RRT providers, who are not specifically defined as "electric utilities" under the EUA. The CG submitted that the Board should expand the application of Directive 014 to include all RRT providers. The CG would like to see all RRT providers comply with the Directive by December 31, 2006.

EEC submitted that if the Board amends Directive 014, then any such amendment should not apply until the 2007 test year, in order to give EEC sufficient time to ensure that the appropriate internal reporting and accounting processes are in place to permit full compliance with the amended Directive.

On January 19, 2005, the EUB issued Directive 014 which sets out the annual financial and operating reporting requirements to be filed by electric utilities with the EUB in accordance with the *Public Utilities Board Act,* R.S.A. 2000 c.P-45 (PUBA). The EUB developed Directive 014 in consultation with representatives of the industry and other interested parties. The purpose and intent behind Directive 014 is to create a uniform reporting requirement applicable to all electric utilities in order "to assist the EUB in conducting its surveillance function efficiently and to provide electric utilities with clear rules and timelines for fulfilling their statutory obligations."[95] Administration of Directive 014 is performed by the staff in the Audit and Compliance Group (A&C Group) of the EUB Utilities Branch who understand the scope and application of Directive 014 and monitor the utilities' compliance with the Directive.

[94] EEC Application, Section 8, p. 2
[95] Information Bulletin 2005-002

CPUC Decision 06-05-016 May 11, 2006
OPINION ON SOUTHERN CALIFORNIA EDISON COMPANY'S TEST YEAR 2006 GENERAL RATE INCREASE REQUEST

Decision 06-05-016 May 11, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) For Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2006, And to Reflect That Increase in Rates.	Application 04-12-014 (Filed December 21, 2004)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Southern California Edison Company.	Investigation 05-05-024 (Filed May 26, 2005)

(*See* Appendix A for a List of Appearances.)

OPINION ON SOUTHERN CALIFORNIA EDISON COMPANY'S TEST YEAR 2006 GENERAL RATE INCREASE REQUEST

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OPINION ON SOUTHERN CALIFORNIA EDISON COMPANY'S TEST YEAR 2006 GENERAL RATE INCREASE REQUEST

1. Introduction

1.1 Summary of Decision

This decision addresses the general rate increase request of the Southern California Edison Company (SCE). For test year 2006, SCE is authorized a revenue requirement of $3,749,292,000, which reflects an increase of $333,115,000 or 9.75% over the previously authorized level of $3,416,177,000. The adopted methodology for calculating post-test year revenue requirements results in additional revenue requirement increases of $143,350,000 (3.82%) for post-test year 2007 and $192,573,000 (4.95%) for post-test year 2008. On a general rate case (GRC) revenue basis, when reflecting the effect of increased sales for the test year and post-test years, the revenue increases amount to $273,455,000 (7.87%) for 2006, $73,541,000 (1.93%) for 2007 and $104,055,000 (2.61%) for 2008. On a total system revenue basis, the revenue increases amount to 2.74% for 2006, 0.72% for 2007 and 1.00% for 2008. For test year 2006, this decision also reflects a one-time $139,559,000 reduction for an overcollection in post-retirement benefits other than pensions (PBOPs).[1]

In brief summary, the decision also:

- Assumes a temporary shutdown of the Mohave Generating Station (Mohave) and reflects costs for this scenario, as forecasted by SCE. All costs will be booked to a two-way balancing account and will be subject to reasonableness review.

[1] This results in a reduced revenue increase of $133,896,000 for 2006 (3.85% on a GRC revenue basis or 1.34% on a total system revenue basis). Since it is a one-time reduction, there would be a corresponding revenue increase in 2007.

- Orders SCE to establish a Mohave Sulfur Credit Sub-Account to accumulate revenues from the sale of any sulfur credits created by the December 31, 2005 Mohave closure. Funds should not be disbursed from this sub-account without specific Commission authorization to do so. The issue of the distribution of revenues accumulated in the Mohave Sulfur Credit Sub-Account will be addressed in a separate proceeding when more information on the future operating status of Mohave is known.
- Excludes costs for SCE's proposed Project Development Division in rates, but allows SCE to establish a memorandum account to track those costs that support new generation and are not associated with proposed projects. SCE can then seek to include those supportive costs in future rates.
- Approves a stipulation regarding Priority 5 maintenance activities. Such activities will continue to be performed on an opportunity basis, while SCE and the Commission's Consumer Protection and Safety Division work out the details to implement a new maintenance program.
- Modifies SCE's Results Sharing request by requiring SCE to credit ratepayers for any difference between the authorized level for Results Sharing and the Recorded level.
- Adopts The Utility Reform Network's (TURN) recommendation to recognize, for ratemaking purposes, the regulatory liability associated with plant removal costs that do not meet the definition of an Asset Retirement Obligation.
- Adopts the Division of Ratepayer Advocates' (DRAs) proposed net salvage rates for calculating depreciation expense, with the exception of Account 364, distribution poles, towers and fixtures. For Account 364, the decision adopts a compromise net salvage rate proposed by SCE.

- Accepts SCE's forecasted plant additions for 2004 and 2005, subject to a truing up process if the recorded additions are less than forecasted. The truing up process will be performed in conjunction with the Capital Additions Adjustment Mechanism review that will be conducted later this year.
- Rejects proposals to determine the post-test year revenue increases by applying a consumer price index factor to the adopted 2006 revenue requirement. The decision also rejects SCE's proposal to reflect its proposed capital budgets for 2007 and 2008 in determining the revenue increases for the post-test years. Plant additions are instead determined by taking the adopted 2006 test year plant additions and escalating that amount to 2007 and 2008 post-test year dollars.
- Rejects the proposal of San Diego Gas & Electric Company (SDG&E) to establish a Cost Control Incentive Mechanism (CCIM) for the San Onofre Nuclear Generating Station (SONGS).
- Approves a settlement regarding a Reliability Investment Incentive Mechanism.
- Approves a settlement regarding bill calculation services for submetered mobile home parks.
- Reflects SCE's 2006 cost of capital as authorized Decision (D.) 05-12-043.

1.2 Procedural Background

On December 21, 2004, SCE filed Application (A.) 04-12-014 requesting a $568,773,000 revenue requirement increase for test year 2006, based on a proposed base revenue requirement level of $4,060,932,000. Based on its proposed methodology for calculation post-test year revenue requirements, SCE estimated revenue requirement increases of $224,829,000 for post-test year 2007 and $207,273,000 for post-test year 2008. On a GRC revenue basis, the request

Decision 07-03-044 March 15, 2007
OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2007 - 2010

Decision 07-03-044 March 15, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-M) for Authorization, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007.	Application 05-12-002 (Filed December 2, 2005)
Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service, and Facilities of Pacific Gas and Electric Company (U 39-M).	Investigation 06-03-003 (Filed March 2, 2006)

(*See* Appendix A for a List of Appearances.)

OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2007 - 2010

OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2007 - 2010

I. Summary

This Opinion adopts a Settlement Agreement that resolves most issues arising from Pacific Gas and Electric Company's (PG&E) general rate case Application (A.) 05-12-002. The adopted Settlement Agreement increases PG&E's revenue requirement for Gas Distribution, Electric Distribution, and Generation by $213 million in 2007 and by $125 million annually during 2008, 2009, and 2010. PG&E is also allowed to recover an additional $35 million for a refueling outage at the Diablo Canyon nuclear power plant. Compared to the preceding year, this Opinion authorizes an increase in PG&E's general rate case (GRC) revenue requirement of 4.5% in 2007, 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010. The increase in PG&E's overall revenue requirement is 1.4% in 2007, 0.8% in 2008, 1.0% in 2009, and 0.6% in 2010.

The other elements of the adopted Settlement Agreement include the following:

- The addition of a third attrition year, 2010, which shifts PG&E's next GRC to test-year 2011.
- A provision that keeps all 84 of PG&E's front counters open pending further developments in Phase 2 of this proceeding regarding PG&E's proposal to close its front counters.
- A Bill-Calculation Service for mobile home park owners with sub-metered tenants.
- A memorandum of understanding between PG&E and the Disability Rights Advocates (DIRA) wherein PG&E agrees to take certain measures to improve its operations affecting disabled persons.

The increased revenue requirement authorized by this Opinion is effective on January 1, 2007, pursuant to Decision (D.) 06-10-033. This revenue requirement is in addition to increases previously authorized in this proceeding for pensions costs in the amounts of $98 million for 2007, $102 million for 2008, $106 million for 2009, and $111 million for 2010.[1]

There are additional elements of today's Opinion that consist of accounting and reporting requirements. These include a requirement for PG&E to record a regulatory liability for $2.1 billion that PG&E has collected in rates but not yet spent to retire and remove assets from service.

The Settlement Agreement does not address issues raised by the Greenlining Institute (Greenlining). These issues focused on executive pay, supplier diversity, employee diversity, and corporate philanthropy. The issues raised by Greenlining are addressed separately. Greenlining and PG&E were able to resolve these issues, and their accord is adopted by today's Opinion.

This proceeding remains open to consider issues associated with PG&E's request to close many of its customer-service counters.

II. Procedural Background and Chronology

PG&E filed A.05-12-002 on December 2, 2005. In A.05-12-002, PG&E requested, among other things, authority to increase its GRC revenue requirement to $5.238 billion effective January 1, 2007, for Gas Distribution, Electric Distribution, and Electric Generation. Compared to 2006, the requested

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1 These are estimated pension costs. The actual revenue requirement for pension costs will vary depending on several factors. See D.06-06-014 for an explanation of the variance.

GRC revenue requirement for 2007 represented an increase of $524 million, or 11.1%. PG&E requested additional increases in 2008 and 2009.

A prehearing conference (PHC) was held on January 23, 2006. Assigned Commissioner Bohn issued a Ruling and Scoping Memo (ACR) on February 3, 2006, that established the scope and schedule for the proceeding. The ACR called for hearings to begin in May 2006 and a final decision in December 2006 on all issues except PG&E's proposed Performance Incentive Mechanism.

On March 2, 2006, the Commission issued Order Instituting Investigation (I.) 06-03-003, the companion investigation to this GRC. The purpose of I.06-03-003, which was consolidated with A.05-12-002, was to allow the Commission to (1) address matters raised by parties other than PG&E, and (2) issue orders on matters for which PG&E might not be the proponent.

In a related proceeding, A.05-12-021, PG&E requested recovery of contributions made to its employee pension plan in 2006. Granting A.05-12-021 would reduce PG&E's revenue requirement for pension costs in this GRC proceeding. On March 8, 2006, PG&E, the Commission's Division of Ratepayer Advocates (DRA), and the Coalition of California Utility Employees (CCUE) filed a settlement agreement that resolved all issues in A.05-12-021 and all pension-cost issues in this GRC proceeding. Among other things, the settlement allowed PG&E to recover the following GRC revenue requirement for pension costs: $155 million in 2006, $98.2 million in 2007, $101.7 million in 2008, and $106.1 million in 2009. The Commission adopted the uncontested settlement agreement in D.06-06-014.

DRA served its written testimony on GRC issues on April 14, 2006. The following parties served their written testimony on April 28, 2006: the Modesto Irrigation District (Modesto ID), the Merced Irrigation District (Merced ID), the

South San Joaquin Irrigation District (SSJID), DIRA, Aglet Consumer Alliance (Aglet), The Utility Reform Network (TURN), Greenlining, and others. The following parties served rebuttal testimony on May 17, 2006: PG&E, Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), and Southern California Gas Company (SCG).

Ten public participation hearings (PPHs) were held at various locations in PG&E's service territory during April and May, 2006.[2] Hundreds of letters were also received from the public.

On May 30, 2006, the assigned Administrative Law Judge (ALJ) granted the joint motion of PG&E, DRA, and several intervenors to defer to early 2007 PG&E's proposal to close all of its front counters where customers can obtain help, information, and services. A noticed settlement conference regarding PG&E' proposal was held on February 15, 2007.

On May 31, 2006, the ALJ ruled that all issues associated with PG&E's proposed late-payment fee would be removed from this proceeding and considered, as appropriate, in I.03-01-012.[3]

A second PHC was held on May 25, 2006. Twenty-five days of evidentiary hearings were held between May 31 and July 7, 2007. During the evidentiary hearings, the ALJ admitted into the record the written testimony of 118 witnesses and approximately 157 other hearing room exhibits.

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2 The PPHs were held at the following locations: Oakland, Ukiah, Santa Rosa, King City, Salinas, San Louis Obispo, Modesto, Fresno, Woodland, and Chico.

3 I.03-01-012 is the companion investigation to PG&E's previous GRC proceeding, A.02-11-017.

After the conclusion of hearings, PG&E's requested revenue requirement for 2007 stood at $5.109 billion. The decrease from the initial amount in the A.05-12-002 was due to (1) PG&E's concessions on several issues raised by DRA, Aglet, and TURN, and (2) the resolution of pension-cost issues by D.06-06-014. PG&E's revised request for 2007 represented an increase of $395 million, or 8.38%, over its 2006 authorized revenue requirement. By comparison, DRA recommended $4.734 billion for 2007, or $375 million less than PG&E's request.

On August 16, 2006, PG&E and several parties held a noticed settlement conference to discuss a proposed settlement. On August 21, 2006, PG&E and most of the active parties jointly filed a settlement agreement[4] and a motion to adopt the settlement agreement.[5] The Settlement Agreement purports to resolve all issues except those raised by Greenlining. The parties joining in the Settlement Agreement are PG&E, DRA, Modesto ID, Merced ID, SSJID, DIRA, the Western Manufactured Housing Communities Association (WMA),

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4 Settlement Agreement Among Pacific Gas and Electric Company, Division of Ratepayer Advocates, The Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Irrigation District, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Federation, Southern California Edison, Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees. This document is referred to hereafter as "the Settlement Agreement" or "the Settlement."

5 Motion of Pacific Gas and Electric Company, Division of Ratepayer Advocates, The Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Irrigation District, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Federation, Southern California Edison, Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees For Approval of Settlement Agreement. This document is referred to hereafter as the "Settlement Motion." The Settlement Agreement was attached to the Settlement Motion.

California Farm Bureau Federation (CFBF), SCE, SDG&E, SCG, and CCUE (together, the Settling Parties). Most of the Settling Parties join only in certain paragraphs of the Settlement Agreement that resolve the particular issues raised by these Parties.[6] A copy of the Settlement Agreement is in Appendix C of today's Opinion.

Noticed technical conferences regarding the Settlement Agreement were held on August 23 and September 6, 2006. PG&E also responded to several written data requests regarding the Settlement Agreement.

The Settlement Agreement is opposed by Aglet, the Alliance for Nuclear Responsibility and the Sierra Club (ANR/SC), and TURN. Rule 12.2 of the Commission's Rules of Practice and Procedure (Rule 12.2) governs comments filed by parties who contest a settlement agreement. Rule 12.2 states:

> Comments must specify the portions of the settlement that the party opposes, the legal basis of its opposition, and the factual issues that it contests. If the contesting party asserts that hearing is required by law, the party shall provide appropriate citation and specify the material contested facts that would require a hearing. Any failure by a party to file comments constitutes waiver by that party of all objections to the settlement, including the right to hearing.

Comments opposing the Settlement were filed on September 20, 2006, by Aglet, ANR/SC, and TURN. None of these parties requested an evidentiary

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6 Settlement Motion, p. 2, Fn. 1. Modesto ID joins only in paragraphs 1, 2, 3, 10, 11, 19, 49, and 50 of the Settlement. Merced ID joins only in paragraphs 1, 2, 3, 10, 11, 19, and 50. SSJID joins only in paragraphs 1, 2, 3, 10, and 19. DIRA joins only in paragraphs 1, 2, 3, 13A, and 48. WMA joins only in paragraphs 1, 2, 3, 12, and 25. CFBF joins only in paragraphs 1, 2, 3, 13B, and 24. SCE, SDG&E, and SoCalGas join only in paragraphs 1, 2, 3, 13C, and 41. (*See* Settlement, para. 3, conditions M-S.)

hearing on the Settlement.[7] Three sets of reply comments were filed on October 5, 2006, by (1) SCE, (2) jointly by SDG&E and SCG, and (3) jointly by the Settling Parties other than SCE, SDG&E, and SCG.

As noted earlier, the Settlement Agreement does not resolve issues raised by Greenlining. These issues – which include executive compensation, supplier diversity, employee diversity, and corporate philanthropy – were the subject of separate briefs. PG&E was the only party to respond to the issues raised by Greenlining. Greenlining filed an opening brief on August 7, 2006. PG&E filed a reply brief on August 21, 2006. Greenlining filed a closing brief on August 28, 2008. PG&E and Greenlining resolved these issues at the last minute in their comments on the Alternate Proposed Decision.

The ACR issued on February 3, 2006, set a schedule that provided for the issuance of a final decision regarding most GRC issues in December 2006. This schedule was extended in several ALJ rulings in order to provide time for the parties to reach a settlement. On August 11, 2006, PG&E filed a motion for the Commission to issue an interim decision that makes PG&E's GRC revenue requirement for the 2007 test year adopted in this proceeding effective on January 1, 2007, in the event the Commission issues a final decision adopting PG&E's GRC revenue requirement after that date. The Commission granted PG&E's unopposed motion in D.06-10-033. As a result, the 2007 GRC revenue requirement authorized by today's Opinion is effective as of January 1, 2007.

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[7] Greenlining's informal request for an evidentiary hearing was denied by the assigned ALJ in a ruling issued on October 6, 2006.

Greenlining and Aglet submitted timely requests pursuant to Rule 13.13(b) for an oral argument before a quorum of the Commission. The oral argument was held on March 2, 2007.

In the remainder of today's Opinion, we will first evaluate the Settlement Agreement and the opposition to the Settlement. We will then address the issues raised by Greenlining.

III. Summary of the Settlement Agreement

The Settlement Agreement purports to resolve all issues in this proceeding except those issues raised by Greenlining. The resolved issues include those raised by Aglet, ANR/SC, and TURN, who are not parties to the Settlement.

The Settlement Agreement adopts a GRC revenue requirement of $4.927 billion in 2007.[8] The following table compares the Settlement revenue requirement with the litigation positions of PG&E and DRA:

[8] The revenue requirement adopted by the Settlement Agreement excludes costs that are (i) regulated by the Federal Energy Regulatory Commission (FERC), and (ii) the subject of other Commission proceedings, including replacement of PG&E's Diablo Canyon steam generators, the Contra Costa 8 generating facility, and Advanced Metering Infrastructure. The Settling Parties agree that under the Settlement there is no double recovery of costs in this GRC and other proceedings.

2007 GRC Revenue Requirement ($ millions)							
		Comparison Exhibit		**Settlement**			
	2006 Authorized	**PG&E**	**DRA**	**Settlement**	**Settlmt. vs. 2006**	**Settlmt. vs. PG&E**	**Settlmt. vs. DRA**
Electric Distrib.	2,648	2,991	2,809	**2,870**	222	(121)	61
Gas Distrib.	1,027	1,062	1,001	**1,047**	21	(15)	46
Generation	1,039	1,056	924	**1,010**	(30)	(46)	86
Total	**4,714**	**5,109**	**4,734**	**4,927**	**213**	**(182)**	**193**
Source: Settlement, Appendix B.							

The GRC revenue requirement adopted by the Settlement for 2007 represents an increase of $213 million, or 4.5%, compared to 2006. On a total system basis, the Settlement increases PG&E's billed revenues by 1.4% in 2007.

The Settlement Agreement adds a third attrition year – 2010 – to the GRC cycle. The Settlement provides for annual attrition increases of $125 million in 2008, 2009, and 2010, and an additional $35 million in 2009 for a refueling outage at Diablo Canyon. The following table compares the Settlement outcome for attrition to PG&E's and DRA's litigation positions:

2008 – 2010 Attrition GRC Revenue Requirement ($ millions)					
	PG&E	**DRA**	**Settlement**	**Settlement vs. PG&E**	**Settlement vs. DRA**
2008	143	100	125	(18)	25
2009	180	131	125	(55)	4
2010	--	--	125	--	--
2009 Diablo Canyon Refueling			35	--	--
Source: Settlement, Appendix E.					

Compared to the immediately preceding year, the Settlement increases PG&E's GRC revenues by 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010. The compound percentage increase over 2007 - 2010 is 12.46%. The above tables show that the Settlement provides PG&E with approximately $634 million less than it requested in cumulative revenues for 2007, 2008, and 2009.[9]

As noted previously, the Settlement divides the GRC revenue requirement among Gas Distribution, Electric Distribution, and Electric Generation. The Settlement further divides the revenue requirement into numerous areas. Some of the specific dollar amounts for 2007 are as follows:

- Operations and maintenance (O&M) expense - $1.079 billion.
- Depreciation expense - $942 million.
- Total Company administrative and general (A&G) expense - $772 million.
- Customer services expense - $431 million.
- Net weighted capital additions - $453 million.
- Rate Base - $12.6 billion.
- Fossil decommissioning refund - $26.8 million.
- Other operating revenues - $116 million.

The Settlement resolves numerous issues that are not expressed in dollar terms. These issues include:

- Forecasts of customers, sales, and revenues at present rates.
- Continuation of the one-way Vegetation Management Balancing Account, and a new Vegetation Management tracking account.
- Uncollectibles factor.
- Various customer fees.

[9] $634 million = (3 x 182 million) + (2 x 18 million) + $55 million.

- Continued operation of all front counters pending further litigation and possible settlement of PG&E's proposal to close its front counters.
- Billing services for mobile home parks.
- Direct access fees.
- Replacement of the Company airplane.
- Capitalization rates.
- A&G allocations to non-GRC operations.
- Franchise fee factor.
- Memorandum of Understanding between DIRA and PG&E.
- O&M labor factors.
- Results of operations model.
- Withdrawal of PG&E's proposed Earnings-Sharing Mechanism.
- Withdrawal of PG&E's proposed Performance-Incentive Mechanism.

The Settling Parties request that the Commission approve the Settlement Agreement without modification and find that the Settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

IV. Standard of Review

The Commission has long favored the settlement of disputes. This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[10] Although the Commission favors the settlement of disputes, Rule 12.2 provides that the Commission will not approve a settlement unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

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[10] D.05-03-022, *mimeo.*, pp. 7-8.

Advice 2838-G/3059-E
(Pacific Gas and Electric Company ID U 39 M)
Quality Assurance Standard Ten for Erroneous Service Termination in Compliance with Decision 07-03-044

Pacific Gas and
Electric Company™

77 Beale Street, Room 1087
P.O. Box 770000
San Francisco, CA 94177

415.973.7000
Fax: 415.973.7226

June 4, 2007

Tariff Files, Room 4005
DMS Branch
Energy Division
505 Van Ness Avenue
San Francisco, CA 94102

Re: Substitute Sheets – Advice 2838-G/3059-E

Quality Assurance Standard Ten for Erroneous Service Termination in Compliance with Decision 07-03-044

Dear Mr. Gatchalian:

Pacific Gas and Electric ("PG&E") filed Advice 2838-G/3059-E with the California Public Utilities Commission on June 1, 2007. The Quality Assurance Standard referenced in Advice 2838-G/3059-E was inadvertently specified as "Quality Assurance Standard Three" instead of the correct title "Quality Assurance Standard Ten." PG&E is hereby submitting substitute sheets to change the language in 2838-G/3059-E from "Quality Assurance Standard Three" to "Quality Assurance Standard Ten."

Attached are the original and 4 copies of substitute sheets for Advice 2838-G/3059-E.

Please telephone me at (415) 973-0237 should you have any questions regarding these substitute sheets. Thank you.

Scott Muranishi
Regulatory Relations

Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

415.973.4977
Fax: 415.973.7226

June 1, 2007 **REVISED**

Advice 2838-G/3059-E
(Pacific Gas and Electric Company ID U 39 M)

Public Utilities Commission of the State of California

Subject: **Quality Assurance Standard Ten for Erroneous Service Termination in Compliance with Decision 07-03-044**

Purpose

In compliance with the 2007 General Rate Case ("GRC") Settlement and Decision (D.07-03-044), Pacific Gas and Electric ("PG&E") submits this filing proposing to adopt Quality Assurance Standard Ten (Attachment 1) under its already existing Quality Assurance Program. This new "shut-off guarantee" standard requires PG&E to pay an amount of one hundred (100) dollars to customers whose gas and/or electric service is erroneously shut-off.

Background

On May 28, 2004, PG&E began implementation of the modified Quality Assurance Program set forth in Appendix B of the 2003 GRC Settlement and Decision (D.04-05-055). PG&E established certain assumptions and expectations defining when and how the nine (9) standards of the Quality Assurance Program would apply. These nine Quality Assurance Standards were established as service guarantees to PG&E customers. In implementing the Quality Assurance Program, PG&E sought the input of the parties that actively participated in this issue during PG&E's 2003 GRC proceeding. These parties are the Commission's Office of Ratepayer Advocates (formally "ORA", now "DRA"), The Utility Reform Network ("TURN"), and the Coalition of California Utility Employees ("CCUE").

In D.07-03-044, TURN proposed the addition of a new quality assurance standard for erroneous service termination. The California Public Utilities Commission ("Commission") ordered that PG&E adopt this new quality assurance standard for erroneous service termination and specified that the new standard should be explained via an advice filing made within ninety (90) days from the March 15, 2007, decision date. It was noted in D.07-03-044 (page 27) that the new quality assurance standard would be beneficial since "it provides compensation to the victims of error; and it provides a strong incentive for PG&E to avoid such errors."

REVISED

Following D.07-03-044 PG&E began working with TURN to develop the particular assumptions and exceptions of the quality assurance standard for erroneous service termination. PG&E and TURN reached agreement concerning the specific language contained herein and is accordingly submitting this proposal for Quality Assurance Standard Ten. Although there have been incidents where PG&E has erroneously discontinued gas and/or electric service to its customers, PG&E is delighted that it will now have a standard remedy in the unfortunate case of such utility error.

The new quality assurance standard found in Attachment 1 provides a detailed explanation of what constitutes an erroneous service termination. PG&E believes that the attached quality assurance standard satisfactorily addresses the requirements as specified in D.07-03-044 and requests its approval.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than **June 21, 2007**, which is 20 days after the date of this filing. Protests should be mailed to:

CPUC Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Avenue
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest also should be sent via U.S. mail (and by facsimile and electronically, if possible) to PG&E at the address shown below on the same date it is mailed or delivered to the Commission:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 M)**

Utility type:	Contact Person: Scott Muranishi
☑ ELC ☑ GAS	Phone #: (415) 973-0237
☐ PLC ☐ HEAT ☐ WATER	E-mail: s3m2@pge.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: **2838-G/3059-E**

Subject of AL: Quality Assurance Standard Ten for Erroneous Service Termination in Compliance with Decision 07-03-044

Keywords (choose from CPUC listing): Quality Assurance Standard Ten

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ____________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

D.07-03-044

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: ____________________

Resolution Required? ☐ Yes ☑ No

Requested effective date: **July 1, 2007** No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Ave.,
San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian K. Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

[1] Discuss in AL if more space is needed.

REVISED

Quality Assurance Standards (“QAS”)
New Standard
Quality Assurance Standard Ten (10)

QAS10 – Terminate Service in Error. “Customers will be compensated with a $100 credit on their bill when gas and/or electric service is/are erroneously terminated by PG&E.”

Erroneous service terminations shall be defined as follows: an error in PG&E’s billing or meter reading practice that results in an inappropriate discontinuance of gas and/or electric service to a customer that has established service with PG&E or has taken all necessary steps to establish service with PG&E.

Assumptions

This guarantee may require customer contact and investigation by PG&E to determine if service was discontinued erroneously.

When possible, PG&E will proactively credit the customer’s account when it is determined that the customer’s service was discontinued in error.

When it is determined that the customer’s service was discontinued in error, PG&E will re-establish service on the same day.

Any service disconnections that occur after 08:00 a.m., where the customer made a sufficient payment or made sufficient payment arrangements the previous day, will be considered an erroneous termination of service. Any service disconnections that occur after 08:00 a.m. on the same day as customer payment will not be considered a termination in error.

Exceptions

This guarantee does not apply to service disruptions which are the subject of other guarantees, specifically, QAS numbers 6, 7, 9, and the Safety Net Program.

If a residential customer fails to pay PG&E for more than 48 hours after receipt of PG&E’s final written notice (the “48-Hour Notice”), such customer will be ineligible for any payment under this service guarantee except where service discontinuance follows a billing or meter reading error.

If a commercial, agricultural, or business customer fails to pay PG&E for more than 24 hours after receipt of PG&E’s final written notice (the “24-Hour Notice”), such customer will be ineligible for any payment under this service guarantee except where service discontinuance follows a billing or meter reading error.

CPUC Decision 07-05-058 May 24, 2007
OPINION ADOPTING A SETTLEMENT AGREEMENT REGARDING THE CLOSURE OF NINE FRONT COUNTERS

Mailed 5/29/2007

Decision 07-05-058 May 24, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-M) for Authorization, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007.	Application 05-12-002 (Filed December 2, 2005)
Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service, and Facilities of Pacific Gas and Electric Company (U 39-M).	Investigation 06-03-003 (Filed March 2, 2006)

OPINION ADOPTING A SETTLEMENT AGREEMENT REGARDING THE CLOSURE OF NINE FRONT COUNTERS

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OPINION ADOPTING A SETTLEMENT AGREEMENT REGARDING THE CLOSURE OF NINE FRONT COUNTERS

1. Summary

This Opinion adopts an uncontested Settlement Agreement (Settlement) that allows Pacific Gas and Electric Company (PG&E) to close nine of its 84 front counters where customers can pay their bills and perform other transactions. The Settlement requires PG&E to provide customers with notice of the closure and to take certain steps to mitigate the impact of the closure on customers. PG&E will reduce its gas and electric rates by a total of $2,757,000 through 2010 to reflect cost savings from the closure.

This Opinion resolves all remaining issues identified in the Scoping Memo and is being issued within 18 months of the Scoping Memo as mandated by Pub. Util. Code § 1701.5.[1] However, this proceeding cannot be closed at this time because of pending applications to rehear a prior decision in this proceeding.

2. Procedural Background and Chronology

PG&E has 84 front counters throughout its service territory that offer a variety of customer services. For example, customers can pay their utility bills with cash at front counters, turn service on and off, resolve billing and service issues, and restore service following discontinuation for nonpayment of bills.

In Application (A.) 05-12-002, PG&E requested, among other things, authority to increase its general rate case (GRC) revenue requirement and to close all 84 of its front counters by June 30, 2007. PG&E asserted that it could provide the services offered by front counters at less cost through its Call Center

[1] All statutory references pertain to the Public Utilities Code.

and Neighborhood Payment Centers (NPCs) operated by third parties. Closing all front counters would reduce PG&E's revenue requirement by $24 million annually starting in 2008. If the Commission rejected PG&E's proposal, PG&E requested $37.1 million in expenses for front counters in 2007 and $0.15 million for capital expenditures in 2007.

The following parties submitted testimony responding to PG&E's proposal to close its front counters: the Division of Ratepayer Advocates (DRA), the California Farm Bureau Federation (CFBF), the Greenlining Institute (Greenlining), and The Utility Reform Network (TURN). The Coalition of California Utility Employees (CCUE) intervened but did not submit testimony.

Ten public participation hearings (PPHs) were held during April and May, 2006.[2] Hundreds of letters were also received from the public. Much of the public's input focused on PG&E's proposal to close all front counters.

On May 26, 2006, most of the active parties for front-counter issues filed a joint motion to defer to Phase 2 of this proceeding all issues regarding PG&E's proposal to close its front counters. The unopposed motion was granted by the assigned Administrative Law Judge (ALJ) in a ruling issued on May 30, 2007.

In Decision (D.) 07-03-044, the Commission resolved all GRC issues except PG&E's proposal to close its front counters. That Decision also provided PG&E with funding to operate all of its front counters, and ordered PG&E to not make any significant reductions to the staffing or operations of its front counters pending the Commission's consideration of front-counter issues in Phase 2.[3]

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2 The PPHs were held in Oakland, Ukiah, Santa Rosa, King City, Salinas, San Luis Obispo, Modesto, Fresno, Woodland, and Chico.

3 D.07-03-044, Ordering Paragraph 5.

The active parties on front-counter reached a settlement and held a noticed settlement conference on February 15, 2007, as required by Rule 12.1(b) of the Commission's Rules of Practice and Procedure (Rule). On April 3, 2007, the active parties filed and served a Settlement Agreement[4] and a Motion to adopt the Settlement.[5] The Settlement resolves all issues regarding PG&E's proposal to close its front counters. The parties that signed the Settlement are PG&E, CFBF, CCUE, DRA, Greenlining, and TURN (together, "the Settling Parties"). A copy of the Settlement Agreement is in Appendix B of today's Opinion.

There were no comments submitted on the Settlement Agreement pursuant to Rule 12.2. Thus, the Settlement is unopposed.

On April 24, 2007, the Settling Parties filed additional information regarding the Settlement in response to an inquiry from the assigned ALJ.

3. Summary of the Settlement Agreement

3.1. The Settling Parties' Litigation Positions

In A.05-12-002, PG&E requested authority to close all 84 of its front counters by June 30, 2007, and to reduce rates by $24 million annually starting in 2008. DRA, CFBF, and TURN opposed any closures. TURN also recommended that PG&E reduce the cost of front counters by 20%. Greenlining did not oppose PG&E's proposal, but expressed concern about the impact that PG&E's proposal

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[4] *Settlement Agreement Among Pacific Gas and Electric Company, Division of Ratepayer Advocates, The Utility Reform Network, the Greenlining Institute, the California Farm Bureau Federation and the Coalition of California Utility Employees* (referred to hereafter as "the Settlement Agreement" or "the Settlement").

[5] *Motion of Pacific Gas and Electric Company, Division of Ratepayer Advocates, the California Farm Bureau Federation, the Coalition of California Utility Employees, the Greenlining Institute and The Utility Reform Network for Approval of Settlement Agreement* filed (referred to hereafter as the "Settlement Motion" or "the Motion").

would have on underserved communities. CCUE intervened on behalf of union members affected by PG&E's proposal.

The Settling Parties represent all the active parties on front-counter issues. They ask the Commission to approve the Settlement Agreement without modification and to find that the Settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

3.2. Summary of the Settlement Terms

The Settlement Agreement allows PG&E to close nine of its 84 front counters within six months of Commission approval. The front counters to be closed are located in Alameda, Corcoran, Geyserville, Half Moon Bay, Newman, Orland, Petaluma, Willits, and Willow Creek. These front counters were selected based on their relatively low transaction volumes and their proximity to other PG&E front counters. PG&E will reduce rates by a total of $2,757,000 through 2010 to pass through the savings from the closure of the nine front counters.[6]

The Settlement includes a Closure Plan that requires PG&E to notify by mail all customers who have used the nine front counters in the prior 12 months that these counters will be closed. The notice will provide information about alternatives to the closed front counters, including the locations of nearby NPCs. PG&E will also meet with representatives of the towns affected by the closures to discuss ways to reduce the impacts on these communities.[7]

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6 Settlement, paras. 9 and 25. This projected savings of $2,757,000 assumes a July 1, 2007, closure date and will be prorated if the front counters are closed at a later date.

7 Settlement, para. 26 and Attachment 3 of the Settlement.

PG&E will maintain for three years at least the same number of NPCs in close proximity to the nine front counters as existed on January 1, 2007.[8] Each of these NPCs will have a public phone located on premises or within one block that customers can use to call PG&E. PG&E will encourage NPCs to provide multilingual staff, to maximize the hours and days of operation, and to stock brochures on PG&E's low-income programs. PG&E will also work with Greenlining to incorporate additional criteria in PG&E's semi-annual NPC audits to address Greenlining's concerns about NPC service.[9]

On a pilot basis, PG&E will establish a call center for agricultural customers staffed by agricultural specialists. The new call center will have its own toll-free number that is separate from the toll-free number for PG&E's main Call Center. The call center for agricultural customers will be staffed weekdays from 7:00 a.m. to 7:30 p.m. and on Saturdays from 7:00 a.m. to 4:30 p.m. PG&E will work with CFBF to promote the use of this call center. PG&E agrees to operate the pilot program for at least one year, and PG&E may make the program permanent if it proves useful to agricultural customers.[10]

PG&E will dedicate two field representatives to agricultural issues. If an agricultural customer has a problem that cannot be resolved over the phone by the new call center, the problem will be referred to the dedicated field

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8 As required by D.98-07-077, PG&E provided in A.05-12-002 a list of all NPC locations and their general proximity to each of the 84 front counters. (Exhibit PG&E-5-WP06A&B, pp. 6AB-2 to 6AB-6.) PG&E listed a total of 378 NPCs.

9 Settlement, paras. 15, 20, 21, and 22.

10 Settlement, para. 16, and supplemental filing on April 24, 2007.

representative closest to the customer's location. The representative will then call the customer to resolve the issue or schedule a time to meet.[11]

PG&E will not close additional front counters for a minimum of three years from the date the Commission approves the Settlement. After three years, PG&E may seek to close up to 20 additional front counters, but such closures will not occur until after the Commission issues a decision authorizing additional closures in PG&E's 2011 test-year GRC. The other Settling Parties reserve the right to protest any future proposal to close front counters.[12]

Finally, the Settlement provides that PG&E employees affected by the closures may exercise their rights under pertinent labor agreements. The Settlement also requires ratification by appropriate union membership,[13] which was obtained on March 30, 2007.[14]

3.3. Declarations in Support of the Settlement Agreement

The Settlement Motion includes two sworn declarations from PG&E's expert witnesses Steve Phillips and Bruce T. Smith.[15] Phillips states that the nine front counters to be closed represent less than 4% of all payment transactions and less than 3% of all non-payment transactions at front counters in 2005. He also represents that PG&E notified customers of its proposal to close all 84 front counters by (1) mailing notices to all customers, and (2) posting notices at all

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[11] Settlement, para. 17.

[12] Settlement, paras. 9, 10, 11, 12, and 14.

[13] Settlement, paras. 23 and 27.

[14] Settlement Motion, p. 5.

[15] The declarations were admitted into the evidentiary record as Exhibits PG&E-80 and PG&E-81 pursuant to a ruling issued by the assigned ALJ on April 23, 2007.

front counters from September 1, 2005, to October 21, 2005. During this period, PG&E received approximately 1,000 responses. Of the 1,000 responses, 19 were from customers using one of the nine front counters to be closed. Of the 19, one customer supported the closures and 18 opposed. Of the 18 opposing, one thought the co-located field service center was closing, not the front counter. The remaining commentators mostly cited convenience and the ability to talk to a person face-to-face as their reasons for wanting the front counters to stay open.

Mr. Phillips states that payment alternatives exist for all nine front counters in the form of NPCs that provide longer operating hours at all nine sites and alternative language capabilities at six of the nine. Seven of the nine front counters to be closed have an NPC within one mile. Eight of the nine are located within 30 minutes driving time of another PG&E front counter.

Mr. Phillips also asserts that there are no transactions that require a customer to go to a front counter. Payments can be made in a variety of ways, including by mail, NPCs, by phone, electronic debiting, and on-line at pge.com. Phillips states that all non-payment transactions can be handled by calling PG&E's regular toll-free number, which is available 24 hours a day and can provide services in over 150 languages.

Mr. Smith's declaration provides the details of the forecasted total savings of $2,757,000 through 2010 from the closure of the nine front counters.

4. Discussion

4.1. Standard of Review

Rule 12.1(d) provides the following standard of review for all settlements:

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

The proponents of a settlement have the burden of demonstrating that the settlement satisfies Rule 12.1(d).

The Commission favors the settlement of disputes. This policy supports many goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results. This policy weighs against the Commission's alteration of uncontested settlements such as the one before us here. As long as a settlement as a whole is reasonable in light of the record, consistent with the law, and in the public interest, it should be adopted without alteration.[16]

4.2. Reasonable in Light of the Whole Record

There is a broad and detailed record regarding front-counter issues that includes public input at the PPHs, written testimony from several parties,[17] and the two declarations attached to the Settlement Motion. The record shows that adopting the Settlement Agreement will enable PG&E to reduce costs and rates for all customers while maintaining service quality for those who have historically used front counters.

The primary concern of those parties who opposed PG&E's proposal to close all 84 of its front counters was the adverse impact that PG&E's proposal would have on those customers who use front counters. The Settlement Agreement resolves this concern by keeping 75 of 84 front counters open, and closing nine front counters that together represent only 3.3% of all transactions at

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16 D.06-06-014, *mimeo.*, p. 12.

17 The written testimony includes exhibits PG&E-5, Chapters 6, 6A, and 6B; PG&E-5-WP06A&B; PG&E-18, Chapter 29; DRA-9; GI-2; and TURN-2. Although CFBF served written testimony (Exhibit CFBF-1), this testimony was not offered for admittance into the record.

front counters. Thus, the vast majority of customers who use front counters are unaffected by the Settlement.

Of those customers who are affected, the record shows that they will have reasonably comparable alternatives to the services provided by the nine closed front counters because:

- Eight of the nine front counters to be closed are within 30 minutes driving time of at least one other front counter that remains open. (Settlement Agreement, para. 9, Table 1.)
- PG&E will maintain for the next three years at least the same number of NPCs in close proximity to the nine front counters. (Settlement Agreement, para. 15.)
- NPCs are usually open longer hours than front counters. No front counters are open on nights or weekends, while 80% of NPCs are open on Saturday and 40% on Sunday. For customers at risk of shutoff and who wish to make an in-person payment during evenings or weekends, NPCs offer the option to do so. Upon paying their bill at an NPC and obtaining a receipt, customers may then call PG&E's toll-free number, available 24/7, to inform PG&E of their payment. PG&E's customer service representative can then immediately cancel the field order to prevent shutoff. (Exhibit PG&E-18, pp. 29-10 and 29-11.)
- Customers with delinquent bills who need to make payments expeditiously can do so at NPCs or by calling PG&E 24/7. If such customers need to make pay-plan arrangements, they can do so by calling PG&E 24/7. (Exhibit PG&E-18, p. 29-9.)
- PG&E will implement a five-day grace period after the bill is due so there should be no situation where a customer making a payment at an NPC (or via the Call Center) on the bill's due date is charged a late payment fee. (Exhibit PG&E-18, p. 29-19.)
- While six types of nonpayment transactions have historically been handled by front counters exclusively, this is no longer true. These six transactions accounted for approximately 10% of all nonpayment transactions at front counters in 2004. PG&E has

already modified five of the six processes to eliminate the need for customers to visit a front counter for these services. The redesign of the remaining transaction will be completed by early 2007 and prior to closure of any front counters. The redesigned processes are easier for customers in that they no longer have to go to a front counter, but may use the NPCs or the Call Center. Moreover, customers accessing service via the Call Center may do so 24/7 from the convenience of their home, office, or cell phone; and they may obtain service at the Call Center in 150 non-English languages, a clear benefit to many PG&E customers. (Exhibit PG&E-18, pp. 29-12 and 29-13.)

- To meet the special needs of agricultural customers, PG&E will create, on a pilot basis, a call center with its own toll-free phone line staffed by agricultural specialists. If the line is utilized and valued by agricultural customers, PG&E may make this an on-going service. (Settlement Agreement, para. 16.)
- PG&E will dedicate two field representatives to agricultural issues. If an agricultural customer's problem cannot be resolved over the phone, the problem will be referred to the dedicated field representative closest to the customer's location. The field representative will then call the customer to resolve the issue or schedule a time to meet. (Settlement Agreement, para. 17.)
- PG&E and Greenlining will work collaboratively to develop a plan that addresses Greenlining's concerns for underserved communities that rely on front-counters. To this end, Greenlining will help PG&E to identify service improvements. (Exhibit PG&E-18, p. 29-3; Settlement Agreement, para. 22.)
- PG&E's engineering, field, and emergency operations that are co-located with some front counters are not affected by the closure of front counters. (Exhibit PG&E-18, p. 29-14.)

To ensure that affected customers are aware of the alternatives available to them, the Settlement requires PG&E to mail a notice to all customers who have used the nine front counters in the previous 12 months that these front counters will be closed. PG&E will also post a notice at each of the nine front counters for a 45-day period prior to closure. The mailed and posted notices will inform customers of alternate payment options, including the locations of nearby NPCs. Additionally, PG&E will meet with representatives of each of the towns affected by the closures to discuss ways to reduce the impacts on the community.[18]

The Settlement's reduction to PG&E's revenue requirement of $2,757,000 through 2010 is supported by PG&E's uncontested testimony on this matter. TURN recommended a 20% across-the-board reduction for all 84 of PG&E's front counters, which is not adopted by the Settlement. PG&E's rebuttal testimony to TURN's recommendation provides reasonable support for the Settlement outcome on this matter.[19]

A major factor in determining whether a settlement is reasonable is the extent to which the settlement fairly balances the interests at stake.[20] PG&E supports the Settlement in the interest of its shareholders. Rather than close all 84 front counters, PG&E has significantly compromised its position. DRA supports the Settlement in the interest of all public utility customers pursuant to its authority under § 309.5(a). CFBF, Greenlining, and TURN support the Settlement on behalf of the consumer interests they represent. DRA, CFBF, and TURN were originally opposed to any closures, but have agreed to the closure of nine front counters as part of an overall settlement. Greenlining is also supportive because of the measures included in the Settlement to mitigate the effects of closure on underserved communities. CCUE supports the Settlement in the interest of PG&E's union employees. The Settling Parties state that they

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[18] Settlement Agreement, para. 26 and Attachment 3 of the Settlement.

[19] Exhibit PG&E-18, p. 29-18.

[20] D.04-12-015, 2004 Cal. PUC LEXIS 574, *66.

represent all of the affected interests and that the Settlement fairly balances those interests.[21] We agree.

We conclude for the previous reasons that the Settlement is reasonable in light of the whole record. We also find that the Settlement Agreement provides sufficient information to enable the Commission to (1) implement the provisions, terms, and conditions of the Settlement, and (2) discharge its future regulatory obligations with respect to the parties and their interests.

4.3. Consistent with the Law

No party alleges that the Settlement is inconsistent with the law. Based on our review of the Settlement, we find that it complies with all applicable statutes, tariffs, and Commission decisions. Of particular relevance is the Settlement's compliance with D.95-12-055, issued in PG&E's 1996 GRC proceeding. That Decision requires PG&E to (1) obtain Commission approval before it closes any front counters, and (2) describe the notice that PG&E provided to customers regarding a proposed closure, the service alternatives available to customers, and the responses that PG&E received from customers and local officials.[22] PG&E provided a satisfactory demonstration of its compliance with D.95-12-055 in Exhibit PG&E-5 and supporting workpapers.[23]

4.4. The Public Interest

PG&E's front counters are heavily used. Approximately 10% of all customer transactions occur at front counters. During 2005, there were 5,641,305

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21 Settlement Motion, p. 6.

22 D.95-12-055, 1995 Cal. PUC LEXIS 965, *154.

23 Exhibit PG&E-5, pp. 6A-11 to 6A-15. The supporting work papers are contained in Exhibit PG&E-5-WP06A&B.

transactions at front counters,[24] including 188,432 transactions at the nine front counters at issue here.[25]

The importance of the front counters to PG&E's customers was highlighted at the PPHs where numerous speakers said that PG&E's front counters provide essential customer services. For example, several speakers explained that many farm workers lack checking accounts and rely on front counters to pay their bills in cash. Other speakers described how farmers' difficulties with PG&E can be very complicated. These speakers described how the staff at front counters in agricultural communities understand the special needs of farmers and can resolve problems quickly, while the PG&E's representatives in a distant call center are generally unfamiliar with the intricacies of arcane agricultural tariffs.[26]

In light of the clear public need for the services provided by PG&E's front counters, we concur with the Settlement outcome that keeps 75 of 84 front counters open. With respect to the nine front counters slated for closure, we concluded that it is in the public interest to close these front counters, with the resultant savings passed through to PG&E's ratepayers, only if the customers who use these nine front counters have reasonably comparable alternatives.

We find that the Settlement Agreement does provide reasonable alternatives. The nine front counters slated for closure were selected based, in part, on their proximity to front counters that will remain open. As shown in

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24 Exhibit DRA-9, p. 9-16.

25 Settlement Agreement, para. 9, Table 1.

26 See, generally, Reporter's Transcript of the PPHs held in Woodland and Chico on May 17 and 18, 2006, respectively.

Table 1 of the Settlement, eight of the nine front counters are within a 30-minute drive of another front counter. The Settlement also provides that PG&E will maintain for the next three years at least the same number of NPCs in close proximity to the nine front counters.[27] Further, there are no transactions that require a customer to go to a front counter. Payments can be handled in several ways, including by mail, by calling PG&E's toll-free number, on-line at pge.com, and in person at NPCs. All non-payment transactions can be handled by calling PG&E's toll free number, which is available 24/7 and can provide services in over 150 languages.[28]

One of the main concerns expressed at the PPHs was that agricultural customers rely on front counters to resolve problems. To address this concern, the Settlement requires PG&E to (1) establish, on a pilot basis, a call center for agricultural customers that has its own toll-free line and is staffed by agricultural specialists; and (2) dedicate two field representatives to agricultural issues.[29] We find that these measures will ensure that agricultural customers receive service that is reasonable comparable to that provided by the nine closed front counters.

The other major concern expressed at the PPHs was that front counters provide a place where persons without a checking account can pay their utility bills in cash, or where persons can pay their bills at the last minute. The record shows that NPCs accept both cash payments and last-minute payments. Last-minute payments that are non-cash can also be made at any time by calling

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[27] Settlement, para. 15.

[28] Exhibit PG&E-80, Declaration of Stephen Phillips, para. 4.

[29] Settlement, paras. 16 and 17.

PG&E or online at pge.com.[30] We find that these alternatives are reasonably comparable to the services provided by the nine closed front counters.

PG&E agrees in the Settlement Agreement to make a good faith effort to educate customers who use the nine front counters about the available alternatives.[31] Attachment 3 of the Settlement Agreement contains a "Closure Plan" that describes the procedures that PG&E will use to notify customers.

We conclude that the uncontested Settlement is in the public interest because it permits PG&E to reduce costs and rates by closing nine front counters with relatively few transactions while ensuring that customers directly affected by closure receive reasonably comparable service through alternate means.

4.5. Conclusion and Implementation

For all of the previous reasons, we conclude that the uncontested Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest. Therefore, we will grant the Settling Parties' Motion to adopt the Settlement Agreement. In accordance with Rule 12.5, the adopted Settlement Agreement is binding on all parties. Such adoption does not constitute approval of, or precedent regarding, any principle or issue.

The declaration of Bruce T. Smith attached to the Settlement shows that adopting the Settlement reduces PG&E's revenue requirement by a total of $2,757,000 through 2010 (assuming the nine front counters are closed on July 1, 2007). As set forth in the declaration, PG&E shall pass these savings to its customers by reducing the annual base revenue recorded in the electric

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30 Exhibit PG&E 18, Chapter 29, pp. 29-9 - 29-11.

31 Settlement, para. 13.

Distribution Revenue Adjustment Mechanism and the gas Core Fixed Cost Account. These savings shall be allocated 55% to electric and 45% to gas.

PG&E shall file advice letters with revised tariff sheets to implement the Settlement. The annual amount credited to customers shall mirror the amounts shown in the declaration of Bruce T. Smith, except the amount for 2007 may be adjusted to reflect the actual date the nine front counters are closed. The advice letters should be filed and processed in accordance with the procedures described in D.07-01-024 and General Order (GO) 96-B for Tier 1 advice letters.

5. Compliance with § 1701.5

This is a ratesetting proceeding. As such, the Commission is required by § 1701.5 to resolve all issues identified in the scoping memo within 18 months from the date the scoping memo was issued. The assigned Commissioner issued his Ruling and Scoping Memo on February 3, 2006. Today's Opinion resolves all remaining issues set forth in the assigned Commissioner's Ruling and Scoping Memo and within the 18-month period mandated by § 1701.5. However, this proceeding cannot be closed at this time because of two pending applications to rehear D.07-03-044 that were timely filed on April 20, 2007.

6. Waiver of the Comment Period

This is an uncontested matter in which the Commission's Opinion grants the relief requested. Therefore, the otherwise applicable 30-day period for public review and comment is waived pursuant to § 311(g)(2) and Rule 14.6(c)(2).

7. Assignment of Proceeding

John A. Bohn is the assigned Commissioner and Timothy Kenney is the assigned ALJ for this proceeding

Findings of Fact

1. The Settlement Agreement is uncontested and is supported by a comprehensive and detailed record.

2. The Settling Parties fairly represent the affected interests.

3. The Settlement Agreement represents a fair compromise of the Settling Parties' positions and interests.

4. The Settlement Agreement provides sufficient information to enable the Commission to (i) implement the provisions, terms, and conditions of the Settlement, and (ii) discharge its future regulatory obligations with respect to the parties and their interests.

5. The Settlement provides customers directly affected by the closure of the nine front counters with reasonably comparable service through alternate means.

6. The Settlement Agreement reduces PG&E's revenue requirement by $2,757,000 for the period of July 2007 through 2010. This reduction may be adjusted based on the date when the nine front counters are actually closed.

7. Today's Opinion resolves all remaining issues identified in the assigned Commissioner's Ruling and Scoping Memo issued on February 3, 2006, and does so within the 18-month period mandated by § 1701.5.

Conclusions of Law

1. The Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest.

2. The Motion to adopt the Settlement Agreement should be granted.

3. To pass through to ratepayers the reduction in PG&E's revenue requirement from the Settlement, PG&E should follow the guidance provided in the declaration of Bruce T. Smith that is attached to the Settlement Agreement.

4. PG&E should file advice letters with revised tariff sheets to implement the Settlement. The advice letters should be filed and processed in accordance with the procedures described in D.07-01-024 and GO 96-B for Tier 1 advice letters.

5. The following order should be effective immediately so that the Settlement Agreement adopted therein may be implemented expeditiously.

O R D E R

IT IS ORDERED that:

1. The Settlement Agreement contained in Appendix B of this Order is adopted.

2. PG&E shall file advice letters with revised tariff sheets to implement the adopted Settlement Agreement. The advice letters shall be filed and processed in accordance with the procedures described in Decision 07-01-024 and General Order 96-B for Tier 1 advice letters. In addition, the advice letters shall be limited to implementing the adopted Settlement Agreement, and shall not incorporate other revenue requirement or tariff changes outside of the Settlement Agreement.

3. The reduction to PG&E's revenue requirement set forth in Attachment 2 of the Settlement Agreement shall be flowed to customers in accordance with the provisions of Attachment 2. The reduction to PG&E's revenue requirement for 2007 that is set forth in Attachment 2 may be adjusted, on a prorated basis, to reflect the date when PG&E actually closes the nine front counters identified in the Settlement Agreement.

4. The Motion to adopt the Settlement Agreement is granted.

This Order is effective today.

Dated May 24, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

CPUC Decision 07-09-041 September 20, 2007
PG&E Back Billing for Estimated Bills

COM/JB2,CRC/MOD-POD/tcg **Date of Issuance 9/24/2007**

Decision 07-09-041 September 20, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, To Increase Revenue Requirements for Electric and Gas Service and to Increase Rates and Charges for Gas Service Effective on January 1, 2003. (U 39 M)	Application 02-11-017 (Filed November 8, 2002)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Pacific Gas and Electric Company.	Investigation 03-01-012 (Filed January 16, 2003)
Application of Pacific Gas and Electric Company Pursuant to Resolution E-3770 for Reimbursement of Costs Associated with Delay in Implementation of PG&E's New Customer Information System Caused by the 2002 20/20 Customer Rebate Program. (U 39 E)	Application 02-09-005 (Filed September 6, 2002)

(See Appendix A for List of Appearances.)

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MODIFIED PRESIDING OFFICER'S DECISION

I. Summary

This decision finds that Pacific Gas and Electric Company (PG&E) systematically violated its tariff Rule 9A by failing to issue bills at regular intervals based on actual metering data. The decision also finds that PG&E violated its tariff Rule 17.1 by issuing backbills related to: 1) periods of no bills ("delayed bills) and 2) periods of estimated bills, where the cause for the estimation was within PG&E's control, beyond the time limits permitted under the tariff. We order PG&E to refund, at shareholder expense, approximately $35 million for these unauthorized charges. We further order PG&E to refund reconnection fees (with interest) and pay credits to certain customers whose service was shutoff for nonpayment of illegal backbills.

II. Factual Background

The essential chronology of facts is undisputed. Increases in PG&E's delayed and estimated bills beginning in 2000 have been associated with PG&E's customer information systems (CIS). The CIS is the primary computer system for creating customer accounts, tracking and managing customer data, calculating and printing bills, and performing hundreds of other core business functions.[1]

The increase in delayed bills in 2000 was attributable to an upgrade to PG&E's legacy CIS system (LCIS) in late 1999. Then in early December 2002 PG&E replaced the nearly 40-year old LCIS because it was outdated, inefficient, and no longer able to keep up with the complexity of the tasks required of it. PG&E's new system is called CorDaptix. As part of the initial CorDaptix roll-out

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[1] PG&E Opening Brief, pp. 19-20.

and as stabilization period, PG&E imposed a moratorium on certain credit and collection activities. Nonetheless customers began complaining about delayed bills in early 2002. And when this moratorium was lifted in May 2003 complaint levels increased. Initially the Commission's Consumer Affairs Branch (CAB) staff acquiesced in PG&E's interpretation that such delayed bills did not violate PG&E's tariffs,[2] but in early 2004 it began to question the correctness of these billing practices.[3] The Consumer Protection and Safety Division and our Executive Director then began to take the corrective steps that led to this investigation.

III. Procedural Background

In 1986, the Commission issued *In re Retroactive Billing* (D.86-06-035, 21 CPUC2d 270 (*Retroactive Billing Decision*)), a decision which established procedures for retroactive billing by gas and electric utilities to correct alleged under-billings. These rules form the basis for the utilities' tariff rules relating to rendering of bills, meter testing and adjustments for meter and billing error, and adjustment of bills for unauthorized use. Among other things, the *Retroactive Billing Decision* found that "a three month limitation period for backbilling residential customers [for undercharges due to meter error or billing error] is sufficient in view of the utilities' assertion that they have procedures to detect billing and meter errors promptly." (*Id.,* 278.)

PG&E's Rule 9 governs the rendering of bills.[4] It provides that bills will be rendered at regular intervals, typically once a month. Rule 9 also provides that,

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[2] *See* Exh.34, pp. 4-3 to 4-6.

[3] *See* Exh 18, pp. 8 – 9.

[4] Unless otherwise indicated, all references to "Rules" are to PG&E's tariff rules.

if for reasons beyond the meter reading entity's control, the meter cannot be read, PG&E will bill the customer for estimated consumption. Rule 17.1 defines billing error and allows PG&E to adjust residential bills for undercharges due to billing error for a period of three months; for nonresidential customers adjustments may be made for a period of three years.

As noted above, in 2003 and 2004, the Commission's Consumer Affairs Branch received a significant number of complaints from PG&E customers claiming that PG&E failed to bill them for actual gas or electric usage on a regular monthly basis as specified in Rule 9. In some cases PG&E failed to issue a bill for several months longer than a three-month period and subsequently issued a single bill covering all the previous months not billed ("backbill"). In other cases, PG&E estimated a customer's bill (including for reasons within PG&E's control) for several months and later rendered a backbill for undercharges associated with the difference between estimated usage and the actual usage during the months usage was estimated. In either event, PG&E failed to treat estimated bills or months of no bills ("delayed bills") as billing errors for purposes of Rule 17.1 and its limits on backbilling.

By letter to PG&E dated October 12, 2004, the Commission's Executive Director noted the numerous customer complaints related to delayed and estimated bills. The Executive Director stated that if PG&E is experiencing circumstances requiring it to estimate so many bills each month, it should proactively address the situation. The Executive Director requested that PG&E stop collecting overdue amounts from residential customers that dated back more than 90 days and referred to Rule 17.1.

In response to the Executive Director's letter, PG&E filed Advice Letter 2581-G/2568-E on October 15, 2004, proposing revisions to its gas and electric tariff to indicate, among other things, that billing error includes failure to issue a bill, but does not include the issuance of an estimated bill.

By Resolution G-3372 dated January 13, 2005, the Commission granted PG&E's proposal in part and denied it in part, finding that failure to issue a bill, as well as issuing an estimated bill due to circumstances within the utility's control, constitutes billing error "consistent with existing CPUC policy, tariffs, and requirements, including the requirements of D.86-06-035." (Resolution G-3372, Finding of Fact 10.)

In the interim, by Assigned Commissioner's Ruling dated February 25, 2005, the Commission undertook this investigation into PG&E's billing and collection practices as a second phase of Investigation (I.) 03-01-012, the companion to PG&E's Test Year 2003 general rate case. The Assigned Commissioner's Ruling, as confirmed by the May 26, 2005, Assigned Commissioner's Scoping Memo and Ruling, provided that the investigation would determine whether, pursuant to Sections 701, 734, and 1702 of the Public Utilities Code,[5] PG&E should be required to refund any amounts collected in violation of Rules 9 and 17.1 and/or be fined pursuant to Sections 2107 and 2108 for violations of the Commission's orders and rules. I.03-01-012 is an adjudicatory matter and *ex parte* contacts are prohibited, pursuant to Public Utilities Code section 1701.2. The period of the investigation is January 2000 to May 2005.

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[5] Unless otherwise specified, all other references to "Sections" are to the Public Utilities Code.

IV. Tariff Violations

In this investigation we have reviewed PG&E's billing obligations and activities under both Tariff Rule 9A and Tariff Rule 17.1.

Tariff Rule 9A provides:

> Bills for electric service will be rendered at regular intervals. All bills will be based on meter registration or actual usage data, except as provided in C and G below, or as may otherwise be provided in PG&E's tariffs.

PG&E's actions, outlined in the chronology of facts, violated Rule 9A's requirement to issue bills at regular intervals based on actual metering data. In Resolution G-3372, as modified by D.05-09-046, we determined that estimated or missing bills due to problems with PG&E's billing system constitutes "billing error" under Rules 9 and 17.1 and are not excused by Rule 9C.[6] We stated:

> In these instances the policy underlying Rule 17.1 would apply. Problems with the implementation of PG&E's new billing system should be treated as billing errors. These examples also are not circumstances in which PG&E may issue estimated bills indefinitely. . . . (Res. G-3372, p. 11.)

It is also undisputed that PG&E issued backbills to these customers that exceeded the limits imposed by Rule 17.1.

There is also substantial evidence that many of PG&E's billing problems were not a result of the change in the billing system, as PG&E contends. The

[6] Rule 9C provides, in relevant part: "Unless estimated bills result from inability to access and change the existing meter to the SmartMeterTM system, inaccessible roads, the customer, the customer's agent, other occupant, animal or physical condition of the property preventing access to PG&E's facilities on the customer's premises, other causes within control of the customer, or a natural or man-made disaster such as a fire,

Footnote continued on next page

testimony of South San Joaquin Irrigation District (SSJID) in this case documents a long-standing pattern of mismanagement and poor customer service relative to accurate billing and in response to related inquiries. For example, PG&E failed to read SSJID meters for months at a time, erroneously calculated the true-ups bills, and billed SSJID for pumps that had been shut down for the season. (Ex. 1, Testimony of Jeffery K. Shields). In one instance, PG&E failed to read a SSJID meter from May 2005 through March 2006, three years after the new billing system was installed. PG&E variously explained that it did not have a key to the meter (which was accessible via a master key in PG&E's possession), that it had an incorrect address for the meter (which PG&E itself had installed), and that PG&E was using contract or temporary meter readers. (Ex. 2, Rebuttal Testimony of Jeffery K. Shields, pp. 2-3.) These explanations are inadequate. In this decision, we will order PG&E to provide SSJID with the estimation calculations underlying disputed 2000 and 2001 bills. Providing the underlying calculations for a bill is the expected response to a reasonable customer inquiry. We limit the time period to 2000 and 2001 because PG&E and SSJID have resolved the billing dispute for 2005-2006.

CPSD also submitted evidence that showed that the billing errors were not solely caused by technical problems with the billing system. For example, PG&E billed a customer for the wrong meter from June 2003 through January 2004, even though the customer had made repeated calls to PG&E to correct the error, and had even given the correct meter number to the customer service representative over the telephone. PG&E backbilled the customer for the entire

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earthquake, flood, or severe storms, the issuance of estimated bills shall be considered "billing error" for the purposes of applying Rule 17.1."

period then erroneously disconnected service even though the customer had made payment arrangements for the illegal backbill. (CPSD Opening Brief, p. 26.)

Rule 17.A was instituted precisely to prevent this type of problem. In Decision 05-09-046, we held that Resolution G-3372 is "consistent with long-standing Commission policy" on backbilling as set forth in Decision 86-06-035 ((1986) 21 Cal P.U.C.2d, 270). Decision 86-06-035 established the three-month limit on backbills and in doing so, put the onus for issuing timely and accurate bills squarely on the utilities, stating, "*[w]e believe a three-month limitation period for backbilling residential customers is sufficient in view of the utilities' assertion that they have procedures to detect billing and meter errors promptly*." (Emphasis in original.) We noted that "[t]he meter after all, is owned, maintained, and, in most cases, read by the utility and the utility accordingly bears the responsibility for promptly detecting and repairing faulty meters." (pp. 2-3.)

The purpose of Rules 9 and 17.1 is two-fold. First, receiving accurate bills issued at regular intervals is a basic consumer right. Customers, particularly those with low or fixed monthly incomes, must have accurate monthly bills in order to properly budget their expenses. As explained by one customer who had not received a bill for twenty months,

> I live paycheck-to-paycheck, and I therefore carefully plan how I use my money. I explained that my electricity usage was based on what I was paying for in the next month's bill. In other words, if I knew that my bills were to be much higher, then I would have been especially determined to find ways to lower the bills, i.e., use less electricity. However, since PG&E had not billed me for almost two years, I had no way of knowing that the electricity bills were to be much higher.
>
> (CPSD Opening Brief, p. 25.)

These concerns apply equally to estimated bills. Unless customers are given bills that are based on actual usage, their ability to budget and/or adjust their electricity usage in response to accurate price signals is hampered. In D.86-06-035 we found that, as a matter of "law, fairness, and customer relations" the utility must be responsible for properly functioning meters and accurate bills, stating "[t]his is particularly true in the case of meter error, where the customer may be unaware of the meter's malfunction and may suddenly be confronted with a large backbill." (pp. 2-3.)

The second goal of the three month backbilling limitation is to provide a strong incentive to PG&E to establish and maintain accurate billing systems. The timely collection of money actually owed is the cornerstone of a sound business, whether that business is a large chain store or a front porch lemonade stand. Undercollection, late collection and overcollection are costly and inefficient and neither the individual customer nor ratepayers as a whole should pay a penalty for the failure of a basic business function that is uniquely within the control of the utility.

This is not a situation where PG&E is charting a course in new territory with unproven technologies. In such a situation, it may be appropriate to spread the risks of such a venture if it would further an important policy goal. Here, PG&E has been providing meter reading and billing functions for over 100 years. This is not a new venture; it is the bread and butter of its business. While the replacement of its outdated Legacy system was an extremely complex and multifaceted undertaking, the fact that these billing problems persisted for as long as they did (including before and after the installation of the Cor-Daptix system) and affected so many customers, as well PG&E's failure to notify this Commission of the problems so that a more pro-active solution to implementation difficulties could be devised, is regrettable.

We cannot condone this pattern of mismanagement and disregard for Commission rules protecting consumer rights. Not only did PG&E cause substantial harm to thousands of customers over a period of five years, it did so notwithstanding the existence of tariff protections that were designed to prevent such harm. PG&E waited until *after* this Commission issued an order instituting investigation (OII) into its billing practices to file an advice letter seeking clarification of the applicability of Rule 17.1 to its repeated billing errors.

It is beyond dispute that PG&E's systematic practice of backbilling due to delayed bills and estimated bills beyond the time limits in Rule 17.1 violated Commission policy and orders and PG&E's tariffs. As the Commission determined in Resolution G-3372 and affirmed on rehearing (*In re Pacific Gas and Electric Co.* (D.05-09-046) 2005 Cal. PUC LEXIS 467), delayed bills and estimated bills where the estimation is for reasons within PG&E's control are billing error for purposes of Rule 17.1 and its limits on backbilling. These tariff violations, which resulted in unauthorized customer charges of approximately $35 million over the period of this investigation, also implicate Public Utilities Code section 532 which provides:

> no public utility shall charge , or receive a different compensation for any product or commodity furnished or to be furnished, or for any service rendered or to be rendered, than the rates, tolls, rentals and charges applicable thereto as specified in its schedules on file and in effect at the time.

Thus, the remaining issue to determine is the appropriate remedy to rectify these violations, consistent with this Commission's regulatory authority. The Assigned Commissioner's Ruling commencing this investigation specified that the Commission's review would consider a range of remedies pursuant to Public Utilities Code sections 701, 734, and 1702, including refunds and/or fines.[7] Under Public Utilities Code section 701, our regulatory authority is broad and wide-ranging. We may "supervise and regulate every public utility in the State and may do all things which are necessary and convenient in the exercise of such power and jurisdiction." In this instance, we act to right a wrong that has adversely affected many thousands of PG&E's customers over a prolonged period of time. Using section 701 as our guide, we will balance the need to find an adequate remedy for all affected customers against the evidence and argument PG&E presents seeking to limit or contain that remedy.

V. Refunds

A. Are Refunds Warranted?

PG&E's charges for backbilled amounts due to delayed bills and estimated bills beyond the time limits in Rule 17.1 are, by definition, excessive. Absent sufficient countervailing reasons, we find that refunds are warranted.[8]

PG&E contends that refunds are not warranted because its backbilling practices did not harm the great majority of customers.[9] According to PG&E, customers are only harmed if they were made worse off economically than they would have been had the same bills been issued timely. We categorically reject PG&E's contention. Customer harm for an excessive charge is properly

[7] Assigned Commissioner's Ruling dated February 25, 2005, Ruling Paragraph 6.

[8] No party contends that refunds will result in discrimination.

[9] PG&E does not oppose partial refunds to CARE customers of 25% of the amounts billed in excess of three months, asserting that those customers were more likely to have been harmed. This percentage represents roughly the CARE discount on rates (20%) and would amount to roughly $50 for the average affected customer. 46 R.T. 4940.

measured against what the charge would have been had the utility complied with its tariff. Pursuant to PG&E's tariffs, PG&E is not entitled to, and customers do not owe, backbilled amounts beyond the three month period provided for in the tariff.[10] Paying amounts that are not owed is without question harmful to customers. Although some customers suffered additional harm such as service termination, reconnection fees, and increased security deposits, PG&E's backbilling practices harmed all improperly backbilled customers.

PG&E argues that customers who receive the benefit of utility service for which they were charged are not harmed, even if the charges were unauthorized; PG&E cites to *In re Cal. Water Service Co.* (D.04-07-033, 2004 Cal. PUC LEXIS 329) as support for this proposition. PG&E misapplies *Cal. Water Service* to the present case. That decision denied refunds to customers who were charged unapproved rates for service following the utility's unauthorized acquisition of the customers' service territories. In that case, however, the customers benefited from the improper charges in the form of lower rates and higher-quality service than they would have otherwise received; under those unusual circumstances, the Commission concluded that refunds were not warranted. In contrast, in the present case, customers were made worse off by PG&E's unauthorized charges than they would have been had PG&E abided by the tariff restrictions on backbilling.

PG&E asks that we decline to order refunds on the basis that customers were simply charged for the energy they consumed and thus received the benefit

[10] Rule 17.1 provides a three-month limit on the backbilling of residential customers and a three-year limit on backbilling non-residential customers in the case of billing error.

Footnote continued on next page

of the service for which they were charged. The Commission addressed the question of whether customers should pay for energy use that is backbilled beyond Rule 17.1 time limits when it adopted the rule, after carefully balancing "matters of law, fairness, and customer relations, […] particularly true in the case of meter error, where the customer may be unaware of the meter's malfunction and may be suddenly confronted with a large backbill" (*Retroactive Billing Decision, supra,**5-6) against the utilities' assertion that they have procedures to detect billing and meter errors promptly (*id*., *21-22). Pursuant to Rule 17.1, the answer is "no." PG&E essentially asks that we revisit the question, and reverse our answer, for purposes of evaluating whether to order refunds. We decline to do so. The considerations that led to our determination that customers should not be charged for energy use beyond Rule 17.1 backbilling time limits apply equally to a determination of whether customers should be refunded for such charges. Denying refunds of amounts charged in violation of Rule 17.1 backbilling time limits, on the basis that customers should pay for energy use even if it is backbilled beyond those time limits, would effectively negate the rule.

B. Who is Responsible for Funding Refunds?

PG&E maintains that paying refunds would strike the wrong balance between the individual customers and the general body of ratepayers who, according to PG&E, are responsible for funding any such refunds. PG&E's argument rests on the premise that ratepayers are responsible for the cost of any

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For simplicity, this decision generally refers to the three-month limit only; however, references to the three-month period generally encompass both time limits.

refunds, which we reject. Shareholders are responsible for funding any refunds for improperly backbilled amounts in violation of Rule 17.1. PG&E's ability to comply with its tariffs is entirely within its control; it is not the ratepayers' responsibility. Were we to assign ratepayers the responsibility for funding refunds that result from PG&E's tariff violations, the utility management would have no incentive to strive for compliance.

PG&E argues that responsibility for funding refunds should correlate to responsibility for funding the undercollections that would have resulted had PG&E complied with Rule 17.1's backbilling limits. As specified in the Preliminary Statements of PG&E's tariffs, bill adjustments – including undercollections -- are reflected in PG&E's various balancing accounts and, ultimately, passed through to PG&E's customers. PG&E contends that, consistent with this treatment of amounts that never were billed because of Rule 17.1 time limits, any refunds for amounts that should not have been collected should likewise be reflected in PG&E's balancing accounts and, ultimately, collected from PG&E's customers.

We disagree. First of all, "[t]he purpose [of reparations] is to return funds to the victim which were unlawfully collected by the public utility." (*Re Standards of Conduct Governing Relationships Between Energy Utilities and Their Affiliates* (D.98-12-075) 84 CPUC2d 155, 188 (*Affiliate Rulemaking Decision).*) Its purpose is not necessarily to place the *utility* in the position *it* would have been in had it not charged the unlawful rate in the first place. Consider, for example, a car accident in which one driver negligently damages another driver's car, and is ordered to pay to repair the car: The purpose of ordering the negligent driver to pay for repairs is to make the victim whole, without regard to the fact that the negligent driver is made worse off than if the accident had never occurred.

Secondly, credits for bill adjustments within Rule 17.1 time limits are not the equivalent of refunds of charges in violation of the time limits. By providing a defined period in which billing errors must be collected, Rule 17.1 sets out very specific parameters for what constitutes acceptable billing error, as opposed to unacceptable charges. PG&E may recover or refund, as the case may be, for billing error within the three-month time limit; the collection of charges beyond that time limit is not acceptable.

Finally, the purpose of revenue balancing accounts is to shield utilities from financial risks that are beyond the utility's control. Even assuming that balancing account treatment is appropriate for uncollected amounts due to Rule 17.1's time limits,[11] the existence of balancing account protection for lawfully collected revenues does not entitle PG&E to balancing account protection for unlawfully collected revenues.

PG&E points to prior Commission decisions as supporting its position that refunds should be afforded balancing account treatment (*i.e.*, ratepayer funded) if the underlying rates in question were balancing account protected. Three of the cited decisions adopt settlements and therefore, pursuant to Rule 12.5 of our Rules of Practice and Procedure, are without precedential effect regarding any principle or issue.[12] The other decision to which PG&E cites, *Salz Leathers, Inc.* v. *Pacific Gas and Electric Co.* (D.91-08-009, 1991 Cal. PUC LEXIS 420), is not on

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[11] We address this assumption later in this decision, with respect to the issue of prospective ratemaking.

[12] *Simpson Paper Co.* v. *Pacific Gas and Electric Co.* (D.95-08-023) 61 CPUC2d 58, *Miller Brewing Co.* v. *Southern California Gas Co.* (D.91-09-075) 41 CPUC2d 409; *California Cogeneration Council* v. *Southern California Gas Co.* (D.94-09-036) 56 CPUC2d 30.

point. The Commission ordered PG&E to refund certain amounts to the complainant (*id*.), and, on rehearing, ultimately ordered that shareholders fund the refunds consistent with PG&E's tariff (*Salz Leathers, Inc.* v. *Pacific Gas and Electric Co.* (D.95-06-010) 60 CPUC2d 254, 257). However, the Commission explicitly declined to find PG&E in violation of any contract, Commission order, or statute. (*Salz Leathers, supra,* 1991 Cal. PUC LEXIS 420, *13-14.) In contrast, the question before us in this proceeding is who should fund refunds in reparation for a tariff violation. *Salz Leathers* is not determinative of this issue.

We likewise reject PG&E's argument that this issue was previously considered in PG&E's 1999 General Rate Case and resolved in PG&E's favor. In that proceeding, the Commission's Office of Ratepayer Advocates (ORA) initially recommended ratemaking treatment for revenues relating to Rules 17 and 17.1 that would have the effect of placing PG&E's shareholders at risk for variations in these revenues, but withdrew its recommendation after further investigation and reflection. More specifically, as discussed in our decision in that proceeding, "[ORA] agreed that revenue adjustments associated with unbilled streetlights and other unmetered facilities, Rule 17 adjustments, and adjustments for revenues collected through PG&E's revenue assurance program should be reflected in Operating Revenues and not in Other Operating Revenues," and the Commission adopted estimates of Other Operating Revenues consistent with that agreement. (*In re Pacific Gas and Electric Company* (D.00-02-046) 2000 Cal. PUC LEXIS 239, *mimeo.* at 235.) The decision did not address the question of who is responsible for funding refunds for violations of the tariff, and so does not inform us here.

PG&E asserts that requiring shareholders to fund refunds, on the basis that it will deter future violations, is punitive. PG&E posits that the question of refunds should therefore be analyzed under the *Affiliate Rulemaking Decision,* which sets forth the Commission's guidelines for determining whether to impose a fine. We do not endorse PG&E's proposition. Certainly, responsibility for funding refunds creates an incentive to guard against the need for refunds. This does not lead us to the conclusion that utilities should only be responsible for funding refunds if they would likewise be liable for fines. Returning to our earlier analogy of the car accident, although responsibility for negligently-caused damages certainly serves as a deterrent against negligent driving, that fact does not transform damage awards into punitive fines, which are allowable only under a higher standard of law.

PG&E asserts that the Commission's characterization of the reimbursement in *CTC Food International, Inc.* v. *Pac. Gas and Elec. Co.* (D.92-10-004, 45 CPUC2d 660) as a "financial penalty" intended to "increase PG&E's incentive" to follow its procedures confirms that shareholder-funded refunds constitute penalties and should be analyzed under the penalty guidelines articulated in the *Affiliate Rulemaking Decision.* This is not the case. Our use of the term "penalty" in *CTC Food International* predated the *Affiliate Rulemaking Decision*, where we undertook to clarify and define the difference between refunds and reparations, on the one hand, and fines and penalties on the other hand. As we explained in the *Affiliate Rulemaking Decision*,

> D.2.a. Reparations
>
> Reparations are not fines and conceptually should not be included in setting the amount of a fine. Reparations are refunds of excessive or discriminatory amounts collected by a public utility. […]
>
> D.2.b. Fines
>
> The purpose of a fine is to go beyond restitution to the victim and to effectively deter further violations by this perpetrator or

> others. For this reason, fines are paid to the State of California, rather than to victims. […] (*Affiliate Rulemaking Decision, supra,* 84 CPUC2d at 188.)

Notwithstanding its vernacular use of the word "penalty," the payment ordered in *CTC Food International* was reimbursement, not a "fine" as we clarified that term in the *Affiliate Rulemaking Decision*.

PG&E further argues that shareholders should not be responsible for funding refunds as matters of policy (*e.g.*, the violation was inadvertent and in good faith; it would be ineffectual as a deterrent measure, it would inappropriately punish PG&E for undertaking important customer service improvements, and it may affect the stability of PG&E earnings and increase the cost of capital) and law (*e.g.*, shareholder funding of refunds before January 1, 2004 is barred by PG&E's bankruptcy settlement). We address these arguments in the context of what refund amounts should be ordered. They do not support reassigning responsibility for funding refunds for tariff violations from shareholders to ratepayers.

For all these reasons, we conclude that shareholders are responsible for funding the required refunds. In order to achieve this result, we direct that PG&E not remove equivalent amounts of revenue from its balancing accounts when it pays the required refunds.

C. What Time Period Should be Used to Determine Refunds?

1. Statute of Limitations

In determining the statute of limitations period, if any, applicable here, we must first understand the nature of the relief being considered. The Commission has determined that PG&E over-billed its customers when it backbilled them for more than the three month period allowed by its tariffs.

Rule 17.1 requires adjusted bills for undercharges to be "computed" by billing the customer for the amount of the undercharge for a period of three months. That Rule also defines "billing error" to include "an incorrect billing calculation." Nevertheless, PG&E repeatedly submitted adjusted bills covering a period of more than three months. Backbilling for more than three months amounts to "billing error," as it constitutes an "incorrect billing calculation" of the adjusted bill. (PG&E Tariff Rule 17.1.) These billing errors resulted in overcharges, in that PG&E customers were being charged amounts they did not owe. In assessing charges contrary to its tariff, PG&E also violated Public Utilities Code section 532.[13]

Some parties argue that the three year statute of limitations contained in Public Utilities Code section 736 applies here, while others contend that because this was a Commission-initiated investigation, no statute of limitations applies. Section 736 provides, in relevant part: "[a]ll complaints for damages resulting from the violation of any of the provisions of Sections 494 or 532 shall . . . be filed with the commission . . . within three years from the time the cause of action accrues, and not after." On its face, section 736 does not appear to be germane to the PG&E backbilling OII because section 736 only applies to complaints for damages filed with the Commission. Here, we initiated a broad investigation to determine if PG&E violated any rules and regulations regarding its billing and collection practices from 2000-2005.

[13] […N]o public utility shall charge, or receive a different compensation for any product or commodity furnished or to be furnished, or for any service rendered or to be rendered, than the rates, tolls, rentals, and charges applicable thereto as specified in its schedules on file and in effect at the time…"

There are two seemingly divergent lines of cases regarding whether Section 736 applies to a Commission-initiated investigation. *In re Hillview Water Co.*, D.03-09-072, p. 28 (*Hillview*), holds that Section 736 does not apply to Commission-initiated investigations. *In re Conlin-Strawberry*, D.05-07-010, pp. 53-54 (*Conlin-Strawberry)*, and *Ridgecrest Heights Water Co.*, 1978 Cal. PUC LEXIS 1459, *11-12 (1978) (*Ridgecrest)*, however, both state that it does.

In *Ridgecrest Heights Water Co.*, the Commission issued an OII to look into whether Ridgecrest had collected connection fees in violation of its tariff and whether it had violated prior Commission decisions. (D.89961, 84 CPUC 612 (1978), p. 613.) This Commission determined that section 736 and its three-year statute of limitations were applicable in this case. (*Id.*, pp. 616-617.) We disagree with the conclusion of *Ridgecrest*. We look to the plain language of section 736 and find that it is clearly not applicable to Commission investigations.

The Commission followed *Ridgecrest* in *Conlin-Strawberry*, although by tolling the statute of limitations, the Commission reached the same result as if it had determined that section 736 was inapplicable. In *Conlin-Strawberry*, the Commission issued an OII after years of reported customer service problems with the utility and allegations of financial irregularities and mismanagement. (*Conlin-Strawberry*, 2005 Cal. PUC LEXIS 294, pp. *5-13.)[14] In addressing whether section 736 applied,[15] the Commission recognized that "[a]n important

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[14] The Commission issued its OII after it had adjudicated a 1995 complaint (C.95-01-038) filed by Strawberry Property Owner's Association (Association) and after the Association had prepared, but not filed, a second complaint against the company in 2001.

[15] Although the Commission determined that Conlin-Strawberry had waived any statute of limitations defenses by failing to plead them soon after the Commission

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distinction should be drawn between these [complaint] decisions (involving non-Commission parties) and an enforcement action brought by the Commission itself to enforce compliance with its own previous order or decision which, arguably, should not be restricted by such a short limitations period." (*Id.*, pp. *82-83.) Nevertheless, relying on *Ridgecrest*, and with little justification, the Commission held that section 736 applied to *Conlin-Strawberry*. However, *Conlin-Strawberry* also determined, in reliance on *Toward Utility Rate Normalization v. Pacific Bell*(1994) 54 CPUC 2d 122 (*Turn v. PacBell),*[16] that "the cause of action for reparations for illegally collected surcharges from 1983 forward did not accrue until October 16, 2003." (*Id.*, pp. *83-85.) Therefore, the applicability of section 736 and a three-year statute of limitations in *Conlin-Strawberry* did not limit the time period for affected ratepayers to obtain refunds for illegal charges.[17]

The Commission reached a different result in *Hillview* regarding section 736. In *Hillview*, the Commission initiated an investigation into a water

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issued the OII (it waited until its appeal of the Presiding Officer's decision) the Commission nevertheless addressed the substantive matter of whether section 736 and its three year statute of limitation applied to the case. (*Conlin-Strawberry*, 2005 Cal. PUC LEXIS 294, pp. *79-82.)

[16] In *TURN* v. *PacBell*, Turn filed a complaint against Pacific Bell alleging that Pacific Bell had unlawfully imposed late payment charges and disconnected customers between 1986 and 1991. In this case, the Commission found that section 736 applied, and that although "the cause of action accrued when consumers were improperly billed . . . the cause of action was delayed (or tolled) until ratepayers became aware of their injury and its negligent cause." (54 CPUC 2d 122, 1994 Cal. PUC LEXIS 313. p. *13.) *Turn* v. *PacBell* is inapplicable to the case at hand because *Turn* v. *PacBell was a complaint case*, while the case at hand is a Commission-initiated investigation.

[17] Practically-speaking, in *Conlin-Strawberry*, the scope of the investigation is what limited the time period for ratepayer refunds, not the statute of limitations.

company to determine whether it had violated the California Public Utilities Code and/or the Commission's Rules of Practice and Procedure. (*Hillview*, p. 4.)[18] In discussing whether section 736's three year statute of limitations applies to Commission-initiated investigation, the Commission determined that section 736 did not apply to this case because "[t]his proceeding is about a tariff violation committed by Hillview, not a claim for damages." (*Hillview*, p. 27.) The Commission further elaborated:

> we . . . conclude that Section 736 does not apply to this proceeding because this proceeding is not a complaint case filed by an aggrieved customer seeking damages from the company, but is an investigatory proceeding instituted by the Commission to determine whether or not the company has violated our rules and/or statutes. The Commission has separate rules and procedures for handling and processing complaint cases and OIIs."

(*Hillview*, p. 28.) We believe that our interpretation of section 736 in *Hillview* is more consistent with the clear language of the statute, state law and the purpose of a statute of limitations than *Ridgecrest* and *Conlin-Strawberry*.

Under California law, there is an assumption that statutes of limitations do not apply to administrative actions, such as this decision here, unless a law specifically imposes a statute of limitations. (3 Witkin Cal. Proc. Actions, § 405 (4th ed. 2006) (*citing Bold v. Board of Med. Examiners* (1933) 133 C.A. 23, 25, 23 P.2d 826; and see *Lam v. Bureau of Sec. & Investigative Services* (1995) 34

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[18] Customer complaints alerted the Commission's Water Division to irregularities with Hillview's regulatory compliance, and the Water Division requested the Commission's Consumer Services Division (since renamed CPSD) to pursue a formal enforcement action. (*Id.*)

C.A.4th 29, 37, 40 C.R.2d 137 [criminal statute of limitations not applicable to administrative proceedings]).) A determination that a statute of limitations does not apply to Commission investigations is also consistent with settled law regarding the purpose of a statute of limitations:

> "Statutes of limitations are designed to promote justice by preventing surprises through the revival of claims that have been allowed to slumber until evidence has been lost, memories have faded, and witnesses have disappeared. The theory is that even if one has a just claim it is unjust not to put the adversary on notice to defend within the period of limitation and that the right to be free of stale claims in time comes to prevail over the right to prosecute them."

(3 Witkin Cal. Proc. Actions, § 408 (4th ed. 2006) (*quoting* *Order of Railroad Telegraphers v. Railway Express Agency* (1944) 321 U.S. 342, 64 S.Ct. 582, 586, 88 L.Ed. 788, 792.) Thus, a finding that the statute of limitations does not apply to the case at hand is consistent with the rationale for a statute of limitations. A decision issued in this Commission investigation is designed to ensure that PG&E's rates, practices and service are reasonable and that violations of law that undermine that goal are properly remedied. Clearly the public interest is not served if the Commission, in a fact-finding investigation of a regulated public utility, must limit the relief it fashions to address violations of state law, as if it were an adversarial litigant.

In conclusion, we decline to apply a statute of limitations to contain the relief awarded in this investigation, and to the extent certain Commission decisions are inconsistent with our approach, we overrule them.[19] The reason is simple: this is not an individual adversarial dispute; rather it is a fact-finding proceeding to ascertain whether PG&E's billing and collection activities were consistent with state law and Commission orders and regulations.[20] We commenced this investigation in PG&E's General Rate Case because our Consumer Affairs Branch (CAB) staff and TURN, an intervenor in that proceeding, alerted us to the serious billing problems PG&E's customers were encountering. Emphatically, this exercise does not involve an adversarial litigation of individual rights. Rather, it is a broad review focused on whether PG&E's billing and collection activities, on a system-wide basis, were in compliance with the law and applicable Commission's requirements. As stated in the Order Instituting Investigation: "[t]he Commission exercises, in connection with general rate cases and other forums, its constitutionally and legislatively derived jurisdiction to regulate PG&E's rates, practices, service, and the reliability, safety, and adequacy of its facilities."[21] Invoking our broad authority under Public Utilities Code section 701, we will order refunds for the entire period of this investigation, an amount approximating $35 million.[22] Not

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[19] The facts and holding of this decision are consistent with the facts and holding of *Peoples Natural Gas Division of Northern Natural Gas Company* v. *Public Utilities Commission of the State of Colorado* (1985) 698 P.2d 255.

[20] Assigned Commissioner's Ruling Ruling Granting TURN's Motion for an Investigation into PG&E's Billing and Collection Practices, Feb. 25, 2005, p. 2.

[21] Order Instituting Investigation, I.03-01-012, Jan. 21, 2003, p. 1.

[22] The February 25, 2005 Assigned Commissioner's Ruling put PG&E on notice that we may issue refunds pursuant to section 701. (Assigned Commissioner's Ruling Granting TURN's Motion for an Investigation into PG&E's Billing and Collection Practices, Feb. 25, 2005, p. 12.)

only is this the right result legally, it is also the right outcome from a fairness standpoint because it provides a remedy to all customers who were adversely impacted by PG&E's backbilling and collection practices during the investigation period.

2. Pre-CorDaptix Data Limitations

There is an issue whether customer refunds for violations of Tariff Rules 9A and 17.1 associated with both estimated bills and delayed bills are due for the period prior to installation of CorDaptix in December 2002. This is the so-called pre-Cordaptix period that runs from January 2000 to December 2002.

PG&E asserts that, as a matter of policy, the Commission should limit the refund period to December 2002 forward because of limitations in the pre-CorDaptix data. With respect to refunds related to delayed bills, PG&E asserts that data limitations in the pre-CorDaptix system result in an inaccurate database of eligible customers. As evidence, PG&E cites to a footnote in the prepared testimony of witness Sharp conceding that a customer, who was not included in the database, should have been (and is now) included. The possibility that not all eligible customers are included in PG&E's old database is not justification for denying refunds to identified eligible customers.

The only further evidence we find on this subject is witness Sharp's additional testimony, in the same footnote, that, "[b]ecause of limitations in the [pre-CorDaptix] data and the absence of certain data, the [pre-CorDaptix] database is both underinclusive and overinclusive," making it "extremely difficult to obtain an accurate list of customers who may have received [illegal] delayed bills for service periods [.…]" This statement is vague and conclusory. It does not support the conclusion that it would be unreasonable to rely on the data for purposes of ordering refunds, as the database is all PG&E has in its possession. We find that the pre-CorDaptix data is sufficiently reliable for purposes of ordering refunds related to delayed bills.

With respect to refunds related to estimated bills, pre-CorDaptix data limitations make it difficult to determine if refunds are due. Rule 17.1 time limits on backbills for estimated bills only apply when the cause of estimation is within PG&E's control. The pre-CorDaptix data does not include the reason for the estimation or whether it was caused by factors within PG&E's control. Thus, although it is feasible to calculate the amount that PG&E backbilled for estimated bills, the available data does not provide definitive information that could be used to calculate a precise refund.

Recognizing this data limitation, TURN recommends that the Commission find that roughly 50% of estimated bills are due to reasons within PG&E's control. TURN's 50% proxy is based on data for February to April 2005 for estimated bills beyond tariff limits where roughly 50% were estimated due to factors within PG&E's control and thus constitute billing error.[23] TURN suggests that the Commission order PG&E to refund 50% of total amount backbilled for estimated bills in excess of the time limits, either by crediting each affected customer in equal parts or in the amount of 50% of their particular backbills. PG&E challenges the reliability of the 50% factor, and contends that this is a further reason for the Commission to refrain from ordering refunds for the pre-CorDaptix period.

While we find TURN's proposed methodology preferable to CPSD's suggestion that we should assume 100% of the estimates were PG&E's fault,

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[23] TURN Opening Brief, p. 13.

TURN's proxy does have some flaws. For example, the 50% proxy is derived from data for February through April 2005, but omits the month of January 2005; if January were included, more than 80% of the estimates would have been found to have been caused by factors outside of PG&E's control. TURN's witness excluded January based on speculation that PG&E was less rigorous in listing reason codes in January – when the Commission issued Resolution G-3372, and PG&E automated the cancel-and-rebill function in CorDaptix – than after those events. This is not a compelling reason for excluding January from the 2005 data. TURN's witness relied more heavily on the 2003 data as substantiating the 50% factor. However, that data is also flawed: The data for 2003 was negatively affected by the absence of missed meter code information, because TURN treated the absence of missed meter codes as though the cause for the estimate was within PG&E's control.

TURN maintains that PG&E's data limitations should not prevail as an excuse to deny refunds to harmed customers. We agree. The pre-CorDaptix data may well be unreliable for purposes of identifying illegal charges related to estimated bills; however, this is a PG&E problem that should not be shifted to the innocent affected customers. PG&E maintains that the cost of developing a method to accurately calculate the refund amount is approximately $600,000, while the amount of the refund should be in the range of $300,000. TURN agrees that this $300,000 figure is a reasonable estimate of the refund amount.[24] Therefore we will order PG&E to refund this amount for illegal charges related to estimated bills in the pre-CorDaptix period. In making these refunds, the burden

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[24] *See* 48 R.T., 5258 – 5303.

of proof is on PG&E, not on the customer who was charged in violation of Rule 9A.

3. Time Allowance for CorDaptix Stabilization

PG&E asks that the Commission shorten the refund period to December 2003 forward to allow a one-year grace period following the implementation of CorDaptix. PG&E contends that, because it usually takes one year after implementation for a utility to return to its pre-conversion performance metrics, and in light of PG&E's exemplary performance in implementing CorDaptix, denying this one-year grace period would punish PG&E for its successful improvement of its outdated customer information system. While we do not wish this action to discourage a utility from undertaking an upgrade to an outdated billing system, we deny PG&E's request for reasons set forth below.

In essence, PG&E seeks an after-the-fact exemption from Rule 17.1's implicit requirement that it remedy all estimated and delayed bill problems within three months. This policy and rule has been in effect since 1989. PG&E's practice of backbilling beyond the tariff time limits was in place and well-established pre-CorDaptix and continued during its implementation and beyond.

We recognize that, notwithstanding PG&E's undisputed exemplary performance during the CorDaptix implementation, this undertaking unavoidably caused an increase in the number of delayed and estimated bills. However, the identified causes for this increase did not require delayed bills or estimated bills to persist beyond the tariff time limits. For example, while programming errors caused the rejection of thousands of valid meter reads, and thus the issuance of estimated bills, in December 2002 and January 2003, there is no apparent reason that a timely backbill could not have issued in February or March 2003 after the programming error had been corrected. Even in the case of data errors that went undetected for nearly a year, PG&E could have looked into correcting the problem on a timelier basis; indeed, the purpose of the tariff's time limits on backbilling is to give PG&E an incentive to do just that.

In sum, the implementation of CorDaptix did not cause PG&E to backbill for delayed and estimated bills in excess of Rule 17.1 time limits, and does not excuse PG&E from the responsibility of refunding those illegal charges.

D. Should Refunds be Waived to Avoid Adverse Financial Consequences?

PG&E contends that refunds will lead to more variable earnings, higher risk and potentially a higher cost of capital to be borne by customers. PG&E explains that, because shareholder funding of refunds would represent a retroactive departure from the balancing account treatment specified in its tariffs, the company would have to reassess whether it can rely on the balancing accounts to provide the authorized revenue. If it determines that it cannot, PG&E explains that will be obliged to report actual revenues on its financial statements, which will lead to these adverse financial consequences.

As we discussed previously, refunds for tariff violations are not the equivalent of bill adjustments that were properly made pursuant to tariff and are not entitled to balancing account treatment.

E. Does the PG&E Bankruptcy Settlement Bar Refunds Pre-December 31, 2003?

PG&E contends that the settlement of PG&E's bankruptcy proceeding, adopted in *Re Pacific Gas and Electric Company* (D.03-12-035, 2002 Cal. PUC LEXIS

1051), is an absolute bar to the Commission ordering refunds of electric revenues accrued prior to December 31, 2003. Paragraph 8a of the settlement provides:

> The Commission acknowledges and agrees that the Headroom, surcharge, and base revenues accrued or collected by PG&E through and including December 31, 2003 are property of PG&E's Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in the Chapter 11 Case, have been included in PG&E's Retail Electric Rates consistent with state and federal, and are not subject to refund. (*Id*., *266, App. C, para 8(a) (emphasis added).)

We do not interpret this settlement provision as barring refunds of illegally collected revenues, as to do so would constitute a suspension of our police power to protect PG&E's ratepayers from unreasonable and unjust rates. As we explained in our decision adopting the bankruptcy settlement,

> In light of the constitutional requirement that the Commission actively supervise and regulate public utility rates (*Sale* v. *Railroad Commission* (1940) 15 Cal. 2d 607 at 617) and the statutory requirements under the §§451, 454, 728 that the Commission ensure that the public utilities' rates are just and reasonable (*Camp Meeker Water System, Inc.* v. *Public Utilities Com*. (1990) 51 Cal. 3d 850 at 861-862), the Commission must retain its authority to set just and reasonable rates during the nine-year term of the settlement and thereafter.
>
> The regulation of utilities is one of the most important of the functions traditionally associated with the police power of the states." (Arkansas Electric Coop. v. Arkansas Pub. Serv. Comm'n (1983) 461 U.S. 375, 377.) This Commission's authority to regulate public utilities in the State of California is pursuant to the State's police power. (See, Motor Transit Company v. Railroad Commission of the State of California (1922) 189 Cal. 573, 581.) The California Supreme Court has held that "it is settled that the government may not contract away its right to exercise the police power in the future." (Avco Community Developers, Inc. v. South Coast Regional Com. (1976) 17 Cal. 3d 785, 800.)

> The Commission cannot be powerless to protect PG&E's ratepayers from unjust and unreasonable rates or practices during the nine-year term of the proposed settlement. "The police power being in its nature a *continuous* one, must ever be reposed somewhere, and cannot be barred or *suspended* by contract or irrepealable law. It cannot be bartered away even by express contract." (*Mott* v. *Cline* (1927) 200 Cal. 434, 446 (emphasis added).)
>
> (*Id.,* *42.)

Given that we retain the authority and obligation to ensure that PG&E's rates are just and reasonable, a more reasonable interpretation of Paragraph 8a is that it bars refunds of headroom, surcharge, and base revenues amounts that were collected in compliance with Commission orders. The amounts charged to customers in violation of Rule 17.1 time limits, whether before or after December 31, 2003, are excessive, and PG&E collected them in violation of Commission orders. We find the bankruptcy settlement does not bar us from exercising our police power to protect ratepayers from the excessive charges by ordering PG&E to refund the illegal charges.

F. How Should Refunds be Calculated?

We find that the proper methodology for calculating refunds excludes the current month's bill from Rule 17.1's three-month backbilling limit, and is limited to the amount of the undercharges.

CPSD interprets the three-month limit as prohibiting backbilling for service before the three billing periods (or 95 days) preceding the date of the backbill. Thus, for example, assuming that PG&E had issued estimated bills (or no bills) for April, May and June, a bill issued on July 31 could properly charge for service only for July, June, and May. PG&E characterizes the July 31 bill as a "current" bill for purposes of July, and interprets the three-month limit as applying to the number of allowable "backbilled" periods which, in our example, include April, May and June. CPSD contends that the Commission has never previously decided which of these interpretations is correct, and suggests that its interpretation is more in line with *Skinner* v. *Pacific Gas & Electric Co.* (D.94-07-050, 55 CPUC2d 408), where the Commission limited backbilling to a three-month period. PG&E contends that *Skinner* decided this issue in its favor, as it did not include the current month of the bill within the three-month backbill period.

Skinner does not control our determination here, as the decision does not explicitly address the specific question of how to determine the allowable backbilling period. We address it now as a matter of first impression. The more reasonable interpretation of the tariff excludes the current month from the allowable backbill period. Using our previous example, we expect that the error that caused PG&E to issue estimated bills (or no bills) for April, May and June was corrected if it was able to issue an accurate current bill for July. Assuming that backbills generally issue with an accurate current bill, CPSD's interpretation would, for practical purposes, limit backbilling to a two-month period of estimated or no bills. Under PG&E's interpretation, the allowable backbill period is a three-month period of estimated (or no) bills. The latter interpretation better reflects the tariff language's reference to a three-month backbilling period.

In its testimony, CPSD suggests that refunds should include all estimated billings beyond three months, not just illegally backbilled amounts. The effect of CPSD's suggested methodology is to provide the consumer with free utility service, even if PG&E cannot correct a 50 cent billing error within three months, but serves no purpose with respect to protecting consumers from untimely bills. This suggested CPSD methodology is unduly draconian.

G. Should Refunds be Paid with Interest?

We decline to order interest on the refund amounts. Interest payments are generally appropriate in order to compensate customers for the time value of money. (*See, e.g., TURN* v. *Pacific Bell* (D.93-05-062) 49 CPUC2d 299, 314.) In this case, although they were illegally charged for it, customers received utility service for the amount of the backbills. Customers who receive refunds will thus have received the benefit of varying amounts of utility service at no cost. This benefit provides adequate compensation, in lieu of interest, to compensate customers for the time value of the illegal charges.

TURN acknowledges Rule 17.1's provision against interest payments on undercharges or overcharges, but argues that it does not apply to refunds for backbilling beyond the rule's time limits. TURN and CPSD also argue that PG&E "clearly erred" in misinterpreting Rule 17.1, and that this constitutes special circumstances that warrant deviation from Rule 17.1's provision against interest pursuant to *Zacky Farms, Inc.* v. *Pacific Gas and Electric Co.* (D.93-11-064, 52 CPUC2d 128). Because we decline to order interest on other grounds, we do not address these arguments.

In its reply brief, CPSD asserts that the cases it cited in its opening brief establish that the standard for imposing interest is whether the utility "clearly erred" or was "derelict in its duty." To the contrary, this standard was established in *Zacky Farms* as a justification for deviating from Rule 17.1's prohibition against interest payments on refunds or undercharges. It does not establish an independent test for determining whether interest should be paid.

H. How Should Eligible Customers be Identified?

PG&E recommends that refunds be limited to customers of record, plus customers identified through the publication of a refund notice in newspapers of general circulation within its service territory in accordance with the procedures used for newspaper notices of PG&E ratemaking applications. PG&E contends that this limitation is consistent with prior Commission-ordered refund plans and straightforward to administer.

TURN recommends that the Commission further require PG&E to make reasonable attempts to locate customers no longer with PG&E, for example by writing to the forwarding address and researching post office records for follow-up addresses, and by issuing press releases to publicize the refunds.[25] PG&E does not raise any specific objections to TURN's recommendation in its briefs and, as it appears reasonable and not unduly burdensome, we adopt it.

In its reply brief, CPSD recommends that the Commission require PG&E to use "standard locator techniques (such as putting names through the National Change of Address database)" and that, if PG&E cannot locate a current address, it should then send refund checks to the last known address. In the absence of a record citation allowing us to determine whether CPSD presented this recommendation in the record of the proceeding, it appears that PG&E has not had an opportunity to respond to it. We therefore reject CPSD's recommendation that we direct PG&E to mail refunds to last known addresses if it cannot locate current addresses. Consistent with our direction that PG&E

[25] This recommendation also appears in TURN's prepared testimony, as cited in TURN's brief.

research post office records for follow-up addresses, we direct PG&E to use standard locator techniques in this effort. However, as we cannot conclude from this record what the National Change of Address data base is, whether PG&E can reasonably access it, or whether it qualifies as a standard locator technique, we allow PG&E the discretion to determine whether to use it in its efforts.

I. Should Unclaimed Refunds Escheat to the State?

We direct that any unclaimed refunds for illegal backbilling charges escheat to the State.

PG&E recognizes that, pursuant to Section 1519.5 of the Code of Civil Procedure (C.C.P.), unclaimed reparations generally escheat to the state. However, it cites to the *Affiliate Rulemaking Decision* for the proposition that the Commission has the discretion to direct otherwise. Specifically, the Commission stated, "Unclaimed reparations generally escheat to the state, unless equitable or other authority directs otherwise, e.g., Public Utilities Code § 394.9." (*Supra,* 84 CPUC2d at 182.) PG&E asserts that, given the overwhelming evidence of its reasonableness and good faith, there is no reason to provide a windfall to the state's general fund in the event certain customers cannot be located.

The Commission does not have blanket discretion to deviate from C.C.P. § 1519.5. C.C.P. § 1519.5 provides:

> Subject to Section 1510, any sums held by a business association that have been ordered to be refunded by a court or an administrative agency including, but not limited to, the Public Utilities Commission, which have remained unclaimed by the owner for more than one year after becoming payable in accordance with the final determination or order providing for the refund, whether or not the final determination or order requires any person entitled to a refund to make a claim for it, escheats to this state.

> It is the intent of the Legislature that the provisions of this section shall apply retroactively to all funds held by business associations on or after January 1, 1977, and which remain undistributed by the business association as of the effective date of this act.
>
> Further, it is the intent of the Legislature that nothing in this section shall be construed to change the authority of a court or administrative agency to order equitable remedies.

The statute is mandatory and includes the Commission within its jurisdiction. Unless another statute (*e.g.*, Section 394.9, which allows the Commission to use unclaimed refunds related to electric service providers for consumer protection efforts) or equitable authority requires the Commission to use the unclaimed refunds for another equitable remedy, they escheat to the state. C.C.P. § 1519.5 does not authorize the Commission to excuse the utility from paying the unclaimed refunds. They shall escheat to the state.

VI. Other Restitution

A. Reconnection Fees and Payments

The parties generally agree that certain customers whose service was shutoff for nonpayment within 75 to 150 days following the receipt of delayed or estimated bills covering service in excess of three months should receive a refund of reconnection fees and a credit of $100 (following delayed bills) or $50 (following estimated bills).[26] The remaining difference concerns which customers should be eligible for these remedies.

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[26] CPSD objects to arbitrarily limiting the refunds to $100 if the customer in fact paid more than $100. It appears that CPSD misunderstands PG&E's proposal, which is to refund the entire reconnection fee, and, in addition, pay a credit of either $100 or $50.

With respect to delayed bills, PG&E proposes to limit refunds to residential customers whose service was shutoff within 75 to 150 days following receipt of a backbill bill in excess of the tariff time limits, and who PG&E identifies as not having been eligible for shutoff at the time of issuance of the illegal backbill. TURN recommends that the default assumption be that the receipt of the illegal backbill caused any shutoff that followed within 75 to 150 days, and that PG&E have the burden of showing on an individual basis which customers had been eligible for shutoff before receiving the illegal backbill. Try as we may, we cannot discern an actual difference between these recommendations. We adopt PG&E's approach as it is more straightforward in its description.

With respect to estimated bills, PG&E similarly proposes to limit refunds to residential customers whose service was shutoff within 75 to 150 days following receipt of an illegal backbill and who PG&E identifies as not having been eligible for shutoff at the time of issuance of the illegal backbill. PG&E proposes, as an additional limitation, that refunds be limited to situations where the amount of the illegal backbill exceeded the customer's average monthly bill over the time period between the accurate meter reads used to determine the backbill amount. PG&E suggests that, in situations where the estimates were extremely accurate and did not involve significant true-up bills, there is no basis to assume that the illegal backbill contributed to the service shutoff. We agree in theory with PG&E's suggestion. However, we cannot find on the basis of this record that backbill amounts up to and including a customer's average monthly bill are insignificant or that they could not have contributed to a service shutoff. In the absence of any reasonable standard for determining a dividing line between significant and insignificant backbill amounts for this purpose, we reject PG&E's proposed additional limitation.

CPSD recommends that PG&E pay interest on the refunded reconnection fees.[27] We agree that interest payments on reconnection refunds are appropriate to compensate customers for the time value of money. We direct that refunds of reconnection fees include interest at the short-term commercial paper rate.[28]

In addition, consistent with our previous discussion regarding refunds of illegal backbill charges, unclaimed refunds of reconnection fees shall escheat to the State pursuant to C.C.P. § 1519.5.

B. Deposits Following Delayed or Estimated Bills

CPSD recommends that PG&E return deposits collected from those customers who were required to pay credit re-establishment deposits within 90 days of receipt of a delayed or estimated bill. PG&E states that CPSD's recommendation is moot. Only the most recent 12 months of a customer's credit history affect whether a customer is required to have a deposit with PG&E, and PG&E's policy has been not to issue delayed and estimated bills in excess of the tariff limits since January 2005 (estimated bills) or October 2004 (delayed bills). PG&E states that any customer deposits that it now holds should be unrelated to delayed or estimated bills in excess of the Rule 17.1 time limits.

[27] Although PG&E acknowledges this recommendation in its briefs, it does not state an objection to it.

[28] TURN recommends this interest rate in its opening brief. No party disputes the appropriate rate.

In its reply brief and without citation to the record, CPSD asserts that PG&E informed staff that it still holds customer deposits required after the presentation of an illegal backbill. CPSD recommends that we direct PG&E to either return the deposits or provide evidence that it has done so. Because there is no record evidence that PG&E continues to hold deposits previously required after presentation of an illegal backbill, we do not adopt CPSD's recommendation.

C. Credit Scores

TURN recommends that the Commission order PG&E to "recall" any notification to credit agencies of unpaid closing bills associated with shutoffs following delayed or estimated bills in excess of tariff time limits. Although PG&E does not have control over the records maintained by credit agencies, it does not state an objection to providing them with the relevant information and requesting that they remove any reference to the nonpayment of the customer's closing bill from their records. We direct PG&E to do so.

D. Contribution to REACH Program

TURN recommends that the Commission encourage PG&E to contribute an additional $1 million to REACH (Relief for Energy Assistance through Community Help),[29] as an appropriate and meaningful gesture of PG&E's commitment to improved customer service going forward. While we certainly encourage PG&E to voluntarily to assist worthy causes in all

[29] REACH is a program for low-income customers who cannot pay their PG&E bill due to financial hardship, and is funded through donations from PG&E shareholders, employees and customers.

communities in which it operates, the Commission declines to order particular charitable contributions to be made.

VII. Penalties

Under Section 2107, any utility that violates any order of the Commission is "subject to a penalty" and the statutory range of Commission penalties is from $500 from $20,000 for each offense. Each day of violation is considered a separate violation. (Section 2108.) The Commission, however, has broad discretion in administering this section of the code and, even while we hold utilities "subject" to a penalty, we may elect to suspend the whole or portion of a penalty or decline to impose a penalty altogether. (*Affiliate Rulemaking Decision.*)

CPSD recommends that Commission impose a $6.75 million fine on PG&E. SSJID supports this recommendation due to PG&E's failure to read meters regularly in violation of Rule 9. We evaluate these recommendations under the criteria for considering penalties set forth in the *Affiliate Rulemaking Decision.*

A. Severity of the Offense

Pursuant to the *Affiliate Rulemaking Decision*, we consider whether there was physical harm; economic harm, either through costs imposed upon victims of the violation or unlawful benefits gained by the utility; or harm to the integrity of the regulatory process. The number of violations is a factor in determining the severity.

1. Physical Harm

We find that, to the extent that customers had their service terminated as the result of nonpayment of illegal backbills, PG&E's conduct caused physical harm. As the United States Supreme Court stated, "Utility service is a necessity of modern life; indeed, the discontinuance of water or heating for even short periods of time may threaten health and safety." (*Memphis Light, Gas & Water*

ALJ/HSY/tcg **Date of Issuance 3/14/2008**

Decision 08-03-012 March 13, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, To Increase Revenue Requirements for Electric and Gas Service and to Increase Rates and Charges for Gas Service Effective on January 1, 2003. (U 39 M)	Application 02-11-017 (Filed November 8, 2002)
Application of Pacific Gas and Electric Company Pursuant to Resolution E-3770 for Reimbursement of Costs Associated with Delay in Implementation of PG&E's New Customer Information System Caused by the 2002 20/20 Customer Rebate Program. (U 39 M)	Application 02-09-005 (Filed September 6, 2002)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Pacific Gas and Electric Company. (U 39 M)	Investigation 03-01-012 (Filed January 16, 2003)

OPINION GRANTING INTERVENOR COMPENSATION TO THE UTILITY REFORM NETWORK FOR SUBSTANTIAL CONTRIBUTION TO DECISION 07-09-041

This decision awards The Utility Reform Network (TURN) $317,900.58 in compensation for its substantial contributions to Decision (D.) 07-09-041. This proceeding is closed.

1. Background

In 2003 and 2004, the Commission's Consumer Affairs Branch received a significant number of complaints from Pacific Gas and Electric Company (PG&E) customers claiming that PG&E failed to bill them for actual gas or electric usage on a regular monthly basis as specified in Rule 9 of PG&E's tariff rules. In some cases, PG&E failed to issue a bill for several months longer than a three-month period and subsequently issued a single bill covering all the previous months not billed ("backbill"). In other cases, PG&E estimated a customer's bill (including for reasons within PG&E's control) for several months and later rendered a backbill for undercharges associated with the difference between estimated usage and the actual usage during the months usage was estimated. In either event, PG&E failed to treat estimated bills or months of no bills ("delayed bills") as billing errors for purposes of tariff Rule 17.1 and its limits on backbilling.

By letter to PG&E dated October 12, 2004, the Commission's Executive Director noted the numerous customer complaints related to delayed and estimated bills and requested that PG&E stop collecting overdue amounts from residential customers that dated back more than 90 days, referring to Rule 17.1. In response, PG&E filed Advice Letter 2581-G/2568-E on October 15, 2004, proposing revisions to its gas and electric tariff to indicate, among other things, that billing error includes failure to issue a bill, but does not include the issuance of an estimated bill.

TURN filed a protest to the advice letter on November 4, 2004, urging the Commission to reject the advice letter and initiate a formal investigation into PG&E's billing and collection practices. The Commission issued Resolution G-3372 on January 13, 2005, finding that failure to issue a bill, as well as issuing an estimated bill due to circumstances within the utility's control, constitutes billing error. (Resolution G-3372, Finding of Fact 10.) PG&E filed A.05-02-022 for rehearing of Resolution G-3372, which the Commission denied in D.05-09-046, on September 22, 2005. PG&E petitioned the California Court of Appeal for writ of review of Resolution G-3372 and D.05-09-046, which was summarily denied on December 5, 2006.

Concurrently, on November 9, 2004, TURN filed a motion in PG&E's 2003 general rate case ("GRC"), Application (A.) 02-11-017, seeking an investigation into PG&E's billing and collection practices. The Assigned Commissioner granted TURN's motion by ruling dated February 25, 2005, and opened the investigation as a second phase of Investigation (I.) 03-01-012, the companion to PG&E's GRC ("backbilling investigation"). On September 24, 2007, the Commission issued D.07-09-041, finding that PG&E systematically violated its tariff Rule 9A by failing to issue bills at regular intervals based on actual metering data and violated its tariff Rule 17.1 by issuing backbills beyond the time limits permitted under the tariff and ordering PG&E to refund, at shareholder expense, approximately $35 million for these unauthorized charges.[1]

2. Requirements for Awards of Compensation

The intervenor compensation program, which is set forth in Pub. Util. Code §§ 1801-1812,[2] requires California jurisdictional utilities to pay the reasonable costs of an intervenor's participation if that party makes a substantial contribution to the Commission's proceedings. The statute provides that the utility may adjust its rates to collect the amount awarded from its ratepayers.

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[1] D.07-09-041 closed the proceedings A.02-11-017. A.02-09-005, and I.03-01-012.

[2] All subsequent statutory references are to the Public Utilities Code unless otherwise indicated.

All of the following procedures and criteria must be satisfied for an intervenor to obtain a compensation award:

1. The intervenor must satisfy certain procedural requirements including the filing of a sufficient notice of intent (NOI) to claim compensation within 30 days of the prehearing conference (PHC), pursuant to Rule 17.1 of the Commission's Rules of Practice and Procedure (Rules), or at another appropriate time that we specify. (§ 1804(a).)
2. The intervenor must be a customer or a participant representing consumers, customers, or subscribers of a utility subject to our jurisdiction. (§ 1802(b).)
3. The intervenor must file and serve a request for a compensation award within 60 days of our final order or decision in a hearing or proceeding. (§ 1804(c).)
4. The intervenor must demonstrate "significant financial hardship." (§§ 1802(g) and 1804(b)(1).)
5. The intervenor's presentation must have made a "substantial contribution" to the proceeding, through the adoption, in whole or in part, of the intervenor's contention or recommendations by a Commission order or decision or as otherwise found by the Commission. (§§ 1802(i) and 1803(a).)
6. The claimed fees and costs must be reasonable (§ 1801), necessary for and related to the substantial contribution (D.98-04-059), comparable to the market rates paid to others with comparable training and experience (§ 1806), and productive (D.98-04-059).

In the discussion below, the procedural issues in Items 1-4 above are combined and a separate discussion of Items 5-6 follows.

2.1. Preliminary Procedural Issues

Rule 17.2 states that a party found eligible in one phase of a proceeding remains eligible in later phases, including rehearing, in the same proceeding. On April 9, 2003, the assigned Administrative Law Judge (ALJ) issued a ruling finding that TURN is a customer as that term is defined in § 1802(b), meets the eligibility requirements of § 1804(a), including the requirement that it establish significant financial hardship, and is eligible for compensation in this proceeding.

Regarding the timeliness of the request for compensation, TURN filed its request for compensation on November 21, 2007, within 60 days of D.07-09-041 being issued.[3] In view of the above, we affirm the ALJ's ruling and find that TURN has satisfied all the procedural requirements necessary to make its request for compensation in this proceeding.

3. Substantial Contribution

In evaluating whether a customer made a substantial contribution to a proceeding, we look at several things. First, we look at whether the Commission adopted one or more of the factual or legal contentions, or specific policy or procedural recommendations put forward by the customer. (§ 1802(i).) Second, we look at if the customer's contentions or recommendations paralleled those of another party and, if so, whether the customer's participation unnecessarily duplicated or materially supplemented, complemented, or contributed to the presentation of the other party or to the development of a fuller record that assisted the Commission in making its decision. (§§ 1801.3(f) and 1802.5.)

As described in § 1802(i), the assessment of whether the customer made a substantial contribution requires the exercise of judgment.

> In assessing whether the customer meets this standard, the Commission typically reviews the record, composed in part of pleadings of the customer and, in litigated matters, the hearing transcripts, and compares it to the findings, conclusions, and

[3] No party opposed the request.

> orders in the decision to which the customer asserts it contributed. It is then a matter of judgment as to whether the customer's presentation substantially assisted the Commission.[4]

Should the Commission not adopt any of the customer's recommendations, compensation may be awarded if, in the judgment of the Commission, the customer's participation substantially contributed to the decision or order. For example, if a customer provided a unique perspective that enriched the Commission's deliberations and the record, the Commission could find that the customer made a substantial contribution. With this guidance in mind, we turn to the claimed contributions TURN made to the proceeding.

TURN claims compensation for substantial contributions to D.07-09-041 as well as to Resolution G-3372 and D.05-09-046, denying rehearing of Resolution G-3372. We address these issues separately.

3.1. D.07-09-041

The Commission initiated the backbilling investigation in response to TURN's motion as well as the number of complaints received by the Commission and issues raised in response to PG&E's Advice Letter 2250-G/2534-E. D.07-09-041 adopted most of TURN's recommendations, concluding that refunds were warranted, that the refunds should be funded by shareholders, that the refunds should not be limited due to data limitations prior to December 2002 or by a statute of limitations, and should be paid to all eligible customers identified through reasonable attempts (as proposed by TURN) to locate customers no longer with PG&E; and ordering additional remedies proposed by TURN for customers who endured termination of service for nonpayment of

[4] D.98-04-059, 79 CPUC2d 628 at 653.

unlawfully backbilled amounts. Although the Commission did not adopt TURN's proposed prospective changes to the ratemaking treatment of undercollections resulting from the backbilling limits of Rule 17.1, TURN's presentation on this issue greatly assisted the Commission in its consideration of whether ratepayers or shareholders should fund the refunds. TURN substantially contributed to D.07-09-041.

3.2. Resolution G-3372 and D.05-09-046

Although we compensate TURN for its costs related to Resolution G-3372 and D.05-09-046, we do so on the basis of TURN's substantial contribution to the backbilling investigation.

TURN cites to D.06-10-013 as standing for the proposition that work related to a substantial contribution to a resolution is compensable if the resolution addresses a similar subject matter as was at issue in a decision in a proceeding. In fact, D.06-10-013 addressed very different circumstances, and did not award compensation for contribution to a resolution on the basis that TURN suggests. D.06-10-013 addressed the issue of whether compensation is warranted for contribution to a resolution that implemented an earlier, related decision, and concluded that "[t]he ongoing work [before the Commission] of [intervenors] to ensure successful implementation of [the related decision] resulted in a substantial contribution to the decision and should be compensated." (D.06-10-013, p. 11.) Here, in contrast, Resolution G-3372 and D.05-09-046 did not implement the related D.07-09-041; rather, they preceded it.

3.3. Intervenor's Contribution Relative to Other Parties

Section 1801.3(f) states that the intervenor compensation statutes are to be administered so as to avoid unproductive or unnecessary participation that duplicates the participation of similar interests otherwise adequately represented by another party, or participation unnecessary for a fair determination of the proceeding. However, § 1802.5 provides that an intervenor's participation that materially supplements, complements, or contributes to the presentation of another party may be fully eligible for compensation if it makes a substantial contribution to the Commission order or decision.

In addition to PG&E and TURN, the Commission's Consumer Protection and Safety Division (CPSD) participated in the proceeding. Although TURN and CPSD represented overlapping interests and supported overlapping recommendations, TURN's participation did not duplicate that of CPSD. TURN carried the bulk of responsibility in testimony, hearings and briefing for ratemaking issues related to refunds. TURN made several specific recommendations adopted by the Commission that were unique and that did not overlap with CPSD's recommendations. On issues where TURN's recommendations overlapped those of CPSD's, such as the statute of limitations issue, TURN presented separate facts or authority which substantially assisted the Commission. We find that TURN's participation materially supplemented, complemented, and contributed to CPSD's presentation and made a substantial contribution to D.07-09-041.

4. Reasonableness of Requested Compensation

TURN requests $317,914.33 for its participation in this proceeding, as follows:

Work on Proceeding				
Attorney Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Robert Finkelstein	2004	18.25	$395.00	$7,208.75
Robert Finkelstein	2005	16.00	$395.00	$6,320.00
Robert Finkelstein	2006	14.75	$405.00	$5,973.75
Robert Finkelstein	2007	3.50	$435.00	$1,522.50
Michel Florio	2004	0.50	$470.00	$235.00
Michel Florio	2005	1.00	$470.00	$470.00
Michel Florio	2006	59.75	$485.00	$28,978.75
Michel Florio	2007	2.75	$525.00	$1,443.75
Hayley Goodson	2004	18.75	$190.00	$3,562.50
Hayley Goodson	2005	207.00	$190.00	$39,330.00
Hayley Goodson	2006	497.75	$195.00	$97,061.25
Hayley Goodson	2007	108.75	$210.00	$22,837.50
Victoria Hartanto	2006	46.00	$100.00	$4,600.00
Subtotal attorney fees:				**$219,543.75**
Expert Witness Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Bill Marcus	2005-4/30/06	4.09	$210.00	$858.90
Bill Marcus	5/1/06-2007	1.75	$220.00	$385.00
Greg Ruszovan	2005-4/30/06	151.39	$155.00	$23,465.45
Greg Ruszovan	5/1/06-2007	23.73	$165.00	$3,915.45

Work on Proceeding				
Attorney Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Expert Witness Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Gayatri Schilberg	2005-4/30/06	259.51	$165.00	$42,819.15
Gayatri Schilberg	5/1/06-2007	120.54	$175.00	$21,094.50
Subtotal expert witness fees:				**$92,538.45**
Expenses				$ 2,917.13
Intervenor Compensation Claim Preparation				
Attorneys	**Year**	**Hours**	**Rate**	**Total**
Robert Finkelstein	2007	2.00	$217.50	$435.00
Hayley Goodson	2005	4.00	$95.00	$380.00
Hayley Goodson	2007	20.00	$105.00	$2,100.00
Subtotal claim preparation				**2,915.00**
Total Requested Compensation				**$317,914.33**

In general, the components of this request must constitute reasonable fees and costs of the customer's preparation for and participation in a proceeding that resulted in a substantial contribution. The issues we consider to determine reasonableness are discussed below:

4.1. Hours and Costs Related to and Necessary for Substantial Contribution

We first assess whether the hours claimed for the customer's efforts that resulted in substantial contributions to Commission decisions are reasonable by determining to what degree the hours and costs are related to the work performed and necessary for the substantial contribution.

TURN documented its claimed hours by presenting a daily breakdown of the hours of its attorneys, accompanied by a brief description of each activity. The hourly breakdown reasonably supports the claim for total hours. The hours claimed for travel time are related to limited, non-routine travel by TURN's attorney and expert witness for events at which their in-person attendance was reasonably required.[5]

4.2. Intervenor Hourly Rates

We next take into consideration whether the claimed fees and costs are comparable to the market rates paid to experts and advocates having comparable training and experience and offering similar services.

TURN seeks an hourly rate of $395 for work performed by Finkelstein in 2004 and 2005. We previously approved this rate in D.05-04-014 and D.05-12-038, and adopt it here.[6] TURN seeks an hourly rate of $405 for work performed by

[5] TURN charged half of actual travel time, consistent with Commission policy of compensating reasonable travel time.

[6] TURN bases its requested 2005 rates for Finkelstein and Florio on its statement that D.05-11-031 previously approved them. TURN's statement is misleading, as D.05-11-031 did not approve any particular rates for any particular representative. Informally, TURN clarified to the ALJ that D.05-11-031 "supports" the requested rates, and suggested that no record clarification or analysis is necessary because D.07-04-010 and D.07-07-039 previously adopted the requested rates on the same showing as TURN makes here. However, D.07-04-010 adopted the rate for Finkelstein on the basis of earlier Commission approval of the same rate, and D.07-07-039 adopted the requested rate for Florio on the basis that it conforms with D.05-11-031; neither decision cites TURN's statement in its support, and we do not assume that it was sufficient to persuade the decisions' results. Nevertheless, we have identified precedent for approving the requested rates, which we cite herein. In the spirit of TURN's request, which asks for an opportunity to provide further information needed in order to adopt the requested rates, and in the interests of assisting the transparency of our decisions

Footnote continued on next page

Finkelstein in 2006. We previously approved this rate in D.06-10-018, and adopt it here. TURN seeks an hourly rate of $435 for work performed by Finkelstein in 2007. We previously approved this rate in D.07-12-026, and adopt it here.

TURN seeks an hourly rate of $470 for work performed by Florio in 2004 and 2005. We previously approved this rate in D.05-01-029 and D.06-07-011, and adopt it here. TURN seeks an hourly rate of $485 for work performed by Florio in 2006. We previously approved this rate in D.06-11-032, and adopt it here. TURN seeks an hourly rate of $525 for work performed by Florio in 2007. This rate includes the 3% cost of living increase, plus the 5% step increase generally authorized for 2007 rates in D.07-01-009. However, D.07-01-009 also provides that step increases may not result in rates above the highest rate for any given range for a given year (D.07-01-009, p. 6). We therefore approve a rate of $520, the highest rate for the range of applicable 2007 rates, for Florio's work.

TURN seeks an hourly rate of $190 for work performed by Goodson in 2004 and 2005. We previously approved this rate in D.05-01-029 and D.05-11-031, and adopt it here. TURN seeks an hourly rate of $195 for work performed by Goodson in 2006, and an hourly rate of $210 for her work performed in 2007. We previously approved these rates in D.07-12-026, and adopt them here.

TURN seeks an hourly rate of $100 for work performed by Hartanto, a law student at the University of California at Berkeley's Boalt Hall who worked as a summer associate with TURN during 2006. We previously approved an hourly

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and speedy resolution of its requests, we advise TURN to revise its showing in its future requests consistent with the guidance given here.

rate of $100 for the work of a summer associate employed by Disability Rights Advocates in D.07-04-032, and adopt it here for Hartanto.

TURN seeks an hourly rate of $210 for work performed by Marcus, of JBS Energy, in 2005. We previously approved this rate in D.06-04-029, and adopt it here. TURN seeks an hourly rate of $220 for work performed by Marcus in 2006. We previously approved this rate in D.07-05-043, and adopt it here.[7]

TURN seeks an hourly rate of $155 for work performed by Ruszovan, of JBS Energy, in 2005 through April 30, 2006. We previously approved this rate for 2005 in D.06-10-018, and adopt it here as requested for Ruszovan's work through April 30, 2006.

TURN seeks an hourly rate of $165 for work performed by Ruszovan for work performed after May 1, 2006. This is TURN's first request for compensation for Ruszovan's work during this period. As TURN points out, this is roughly equivalent to applying the 3% cost of living increase approved for 2006 and 2007 rates in D.07-01-009. Specifically, although TURN requests $27,380.90 for Ruszovan's work based on its requested rates, using an hourly rate of $155 for 2005, and escalating it to $160 for 2006 and $165 for 2007, comes to $27,523.35, a difference of only $142. Given this minor difference, it is reasonable to approve the requested rates for Ruszovan's work.

TURN seeks an hourly rate of $165 for work performed by Schilberg, of JBS Energy, in 2005 through April 30, 2006. We previously approved this rate for 2005 in D.06-04-012, and adopt it here as requested for Schilberg's work through

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[7] More specifically, TURN requests the hourly rate of $210 for Marcus's work through April 30, 2006, and the hourly rate of $220 for Marcus's work after May 1, 2006. As all

Footnote continued on next page

April 30, 2006. TURN seeks an hourly rate of $175 for work performed by Schilberg from May 1, 2006 through 2007. We previously adopted this rate in D.07-12-026. In addition, this is roughly equivalent to applying the 3% cost of living increase approved for 2006 and 2007 rates in D.07-01-009, and reflects the actual rates JBS Energy charged TURN. Specifically, although TURN requests $63,913.65 for Schilberg's work based on its requested rates, using an hourly rate of $165 for 2005, and escalating it to $170 for 2006 and $175 for 2007, comes to $63,565.25, a difference of only $348. Given this minor difference, it is reasonable to approve the requested rates for Schilberg's work.

4.3. Productivity

D.98-04-059 directed customers to demonstrate productivity by assigning a reasonable dollar value to the benefits of their participation to ratepayers. The costs of a customer's participation should bear a reasonable relationship to the benefits realized through its participation. This showing assists us in determining the overall reasonableness of the request.

TURN's participation was productive in that the impact of that participation far exceeded fees and other costs. TURN's participation substantially contributed to the Commission ordering PG&E to refund approximately $35.3 million to customers unlawfully backbilled, to credit approximately $300,000 to customers who lost their utility service for failing to pay unlawful backbills, and to take steps to have any reference to the nonpayment of customers' closing bills related to illegal backbills removed from

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of Marcus's work was performed either in November-December 2005 or May 2006, we approve these rates on a calendar basis, consistent with our past practice.

the customers' credit records. Thus, we find that TURN's efforts have been productive.

4.4. Direct Expenses

The itemized direct expenses submitted by TURN include the following:

Attorney Travel	$40.26
Consultant Travel	$223.95
Legal Research (LEXIS)	$722.70
Deposition/Transcripts	$1,061.95
Photocopying	$807.11
Postage	$32.26
Telephone	$28.90
Total Expenses	**$2,917.13**

The cost breakdown included with the request shows the miscellaneous expenses to be commensurate with the work performed. We find these costs reasonable.

5. Award

We award TURN $317,900.58. This reflects the amount of TURN's requested compensation as set forth in the above tables, adjusted to reflect the $520 rate for Florio's work in 2007.

Consistent with previous Commission decisions, we order that interest be paid on the award amount (at the rate earned on prime, three-month commercial paper, as reported in Federal Reserve Statistical Release H.15) commencing on February 4, 2008, the 75th day after TURN filed its compensation request, and continuing until full payment of the award is made.

We remind all intervenors that Commission staff may audit their records related to the award and that intervenors must make and retain adequate accounting and other documentation to support all claims for intervenor compensation. TURN's records should identify specific issues for which it requested compensation, the actual time spent by each employee or consultant, the applicable hourly rates, fees paid to consultants, and any other costs for which compensation was claimed.

6. Waiver of Comment Period

This is an intervenor compensation matter. Accordingly, as provided by Rule 14.6(c)(6) of our Rules of Practice and Procedure, we waive the otherwise applicable 30-day comment period for this decision.

7. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner, and Hallie Yacknin is the assigned ALJ in this proceeding.

Findings of Fact

1. TURN has satisfied all the procedural requirements necessary to claim compensation in this proceeding.
2. TURN made a substantial contribution to D.07-09-041 as described herein.
3. TURN's requested hourly rates for its representatives, as adjusted herein, are reasonable when compared to the market rates for persons with similar training and experience.
4. TURN requested related expenses that are reasonable and commensurate with the work performed.
5. The total of the reasonable compensation is $317,900.58.
6. The appendix to this opinion summarizes today's award.

Conclusions of Law

1. TURN has fulfilled the requirements of §§ 1801-1812, which govern awards of intervenor compensation, and is entitled to intervenor compensation for its claimed expenses incurred in making substantial contributions to D.07-09-041.

2. TURN should be awarded $317,900.58 for its contribution to D07-09-041.

3. This order should be effective today so that TURN may be compensated without further delay.

4. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The Utility Reform Network (TURN) is awarded $317,900.58 as compensation for its substantial contributions to Decision 07-09-041.

2. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall pay TURN the total award. Payment of the award shall include interest at the rate earned on prime, three-month commercial paper as reported in Federal Reserve Statistical Release H.15, beginning February 4, 2008, the 75th day after the filing date of TURN's request for compensation, and continuing until full payment is made.

3. Application (A.) 02-11-017, A.02-09-005, and I.03-01-012 are closed.

This order is effective today.

Dated March 13, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

APPENDIX

Compensation Decision Summary Information

Compensation Decision:	D0803012	**Modifies Decision? No**
Contribution Decision(s):	D0709041	
Proceeding(s):	A0211017/I0301012/A0209005	
Author:	ALJ Yacknin	
Payer(s):	Pacific Gas and Electric Company	

Intervenor Information

Intervenor	Claim Date	Amount Requested	Amount Awarded	Multiplier?	Reason Change/Disallowance
The Utility Reform Network	11/21/07	$317,914.33	$317,900.58	no	Failure to justify hourly rate

Advocate Information

First Name	Last Name	Type	Intervenor	Hourly Fee Requested	Year Hourly Fee Requested	Hourly Fee Adopted
Robert	Finkelstein	Attorney	The Utility Reform Network	$395.00	2004	$395.00
Robert	Finkelstein	Attorney	The Utility Reform Network	$395.00	2005	$395.00
Robert	Finkelstein	Attorney	The Utility Reform Network	$405.00	2006	$405.00
Robert	Finkelstein	Attorney	The Utility Reform Network	$435.00	2007	$435.00
Michel	Florio	Attorney	The Utility Reform Network	$470.00	2004	$470.00
Michel	Florio	Attorney	The Utility Reform Network	$470.00	2005	$470.00

Michel	Florio	Attorney	The Utility Reform Network	$485.00	2006	$485.00
Michel	Florio	Attorney	The Utility Reform Network	$525.00	2007	$520.00
Hayley	Goodson	Attorney	The Utility Reform Network	$190.00	2004	$190.00
Hayley	Goodson	Attorney	The Utility Reform Network	$190.00	2005	$190.00
Hayley	Goodson	Attorney	The Utility Reform Network	$195.00	2006	$195.00
Hayley	Goodson	Attorney	The Utility Reform Network	$210.00	2007	$210.00
Victoria	Hartanto	Law Student/ Clerk	The Utility Reform Network	$100.00	2006	$100.00
Bill	Marcus	Economist	The Utility Reform Network	$210.00	2005-	$210.00
Bill	Marcus	Economist	The Utility Reform Network	$220.00	2006	$220.00
Greg	Ruszovan	Analyst	The Utility Reform Network	$155.00	2005- 4/30/06	$155.00
Greg	Ruszovan	Analyst	The Utility Reform Network	$165.00	5/1/06-2007	$165.00
Gayatri	Schilberg	Economist	The Utility Reform Network	$165.00	2005- 4/30/06	$165.00
Gayatri	Schilberg	Economist	The Utility Reform Network	$175.00	5/1/06-2007	$175.00

(END OF APPENDIX)

Decision 08-03-012 March 13, 2008
OPINION GRANTING INTERVENOR COMPENSATION TO THE UTILITY REFORM NETWORK FOR SUBSTANTIAL CONTRIBUTION TO DECISION 07-09-041

Decision 08-03-012 March 13, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, To Increase Revenue Requirements for Electric and Gas Service and to Increase Rates and Charges for Gas Service Effective on January 1, 2003. (U 39 M)	Application 02-11-017 (Filed November 8, 2002)
Application of Pacific Gas and Electric Company Pursuant to Resolution E-3770 for Reimbursement of Costs Associated with Delay in Implementation of PG&E's New Customer Information System Caused by the 2002 20/20 Customer Rebate Program. (U 39 M)	Application 02-09-005 (Filed September 6, 2002)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Pacific Gas and Electric Company. (U 39 M)	Investigation 03-01-012 (Filed January 16, 2003)

OPINION GRANTING INTERVENOR COMPENSATION TO THE UTILITY REFORM NETWORK FOR SUBSTANTIAL CONTRIBUTION TO DECISION 07-09-041

This decision awards The Utility Reform Network (TURN) $317,900.58 in compensation for its substantial contributions to Decision (D.) 07-09-041. This proceeding is closed.

1. Background

In 2003 and 2004, the Commission's Consumer Affairs Branch received a significant number of complaints from Pacific Gas and Electric Company (PG&E) customers claiming that PG&E failed to bill them for actual gas or electric usage on a regular monthly basis as specified in Rule 9 of PG&E's tariff rules. In some cases, PG&E failed to issue a bill for several months longer than a three-month period and subsequently issued a single bill covering all the previous months not billed ("backbill"). In other cases, PG&E estimated a customer's bill (including for reasons within PG&E's control) for several months and later rendered a backbill for undercharges associated with the difference between estimated usage and the actual usage during the months usage was estimated. In either event, PG&E failed to treat estimated bills or months of no bills ("delayed bills") as billing errors for purposes of tariff Rule 17.1 and its limits on backbilling.

By letter to PG&E dated October 12, 2004, the Commission's Executive Director noted the numerous customer complaints related to delayed and estimated bills and requested that PG&E stop collecting overdue amounts from residential customers that dated back more than 90 days, referring to Rule 17.1. In response, PG&E filed Advice Letter 2581-G/2568-E on October 15, 2004, proposing revisions to its gas and electric tariff to indicate, among other things, that billing error includes failure to issue a bill, but does not include the issuance of an estimated bill.

TURN filed a protest to the advice letter on November 4, 2004, urging the Commission to reject the advice letter and initiate a formal investigation into PG&E's billing and collection practices. The Commission issued Resolution G-3372 on January 13, 2005, finding that failure to issue a bill, as well as issuing an estimated bill due to circumstances within the utility's control, constitutes billing error. (Resolution G-3372, Finding of Fact 10.) PG&E filed A.05-02-022 for rehearing of Resolution G-3372, which the Commission denied in D.05-09-046, on September 22, 2005. PG&E petitioned the California Court of Appeal for writ of review of Resolution G-3372 and D.05-09-046, which was summarily denied on December 5, 2006.

Concurrently, on November 9, 2004, TURN filed a motion in PG&E's 2003 general rate case ("GRC"), Application (A.) 02-11-017, seeking an investigation into PG&E's billing and collection practices. The Assigned Commissioner granted TURN's motion by ruling dated February 25, 2005, and opened the investigation as a second phase of Investigation (I.) 03-01-012, the companion to PG&E's GRC ("backbilling investigation"). On September 24, 2007, the Commission issued D.07-09-041, finding that PG&E systematically violated its tariff Rule 9A by failing to issue bills at regular intervals based on actual metering data and violated its tariff Rule 17.1 by issuing backbills beyond the time limits permitted under the tariff and ordering PG&E to refund, at shareholder expense, approximately $35 million for these unauthorized charges.[1]

2. Requirements for Awards of Compensation

The intervenor compensation program, which is set forth in Pub. Util. Code §§ 1801-1812,[2] requires California jurisdictional utilities to pay the reasonable costs of an intervenor's participation if that party makes a substantial contribution to the Commission's proceedings. The statute provides that the utility may adjust its rates to collect the amount awarded from its ratepayers.

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[1] D.07-09-041 closed the proceedings A.02-11-017. A.02-09-005, and I.03-01-012.

[2] All subsequent statutory references are to the Public Utilities Code unless otherwise indicated.

All of the following procedures and criteria must be satisfied for an intervenor to obtain a compensation award:

1. The intervenor must satisfy certain procedural requirements including the filing of a sufficient notice of intent (NOI) to claim compensation within 30 days of the prehearing conference (PHC), pursuant to Rule 17.1 of the Commission's Rules of Practice and Procedure (Rules), or at another appropriate time that we specify. (§ 1804(a).)
2. The intervenor must be a customer or a participant representing consumers, customers, or subscribers of a utility subject to our jurisdiction. (§ 1802(b).)
3. The intervenor must file and serve a request for a compensation award within 60 days of our final order or decision in a hearing or proceeding. (§ 1804(c).)
4. The intervenor must demonstrate "significant financial hardship." (§§ 1802(g) and 1804(b)(1).)
5. The intervenor's presentation must have made a "substantial contribution" to the proceeding, through the adoption, in whole or in part, of the intervenor's contention or recommendations by a Commission order or decision or as otherwise found by the Commission. (§§ 1802(i) and 1803(a).)
6. The claimed fees and costs must be reasonable (§ 1801), necessary for and related to the substantial contribution (D.98-04-059), comparable to the market rates paid to others with comparable training and experience (§ 1806), and productive (D.98-04-059).

In the discussion below, the procedural issues in Items 1-4 above are combined and a separate discussion of Items 5-6 follows.

2.1. Preliminary Procedural Issues

Rule 17.2 states that a party found eligible in one phase of a proceeding remains eligible in later phases, including rehearing, in the same proceeding. On April 9, 2003, the assigned Administrative Law Judge (ALJ) issued a ruling finding that TURN is a customer as that term is defined in § 1802(b), meets the eligibility requirements of § 1804(a), including the requirement that it establish significant financial hardship, and is eligible for compensation in this proceeding.

Regarding the timeliness of the request for compensation, TURN filed its request for compensation on November 21, 2007, within 60 days of D.07-09-041 being issued.[3] In view of the above, we affirm the ALJ's ruling and find that TURN has satisfied all the procedural requirements necessary to make its request for compensation in this proceeding.

3. Substantial Contribution

In evaluating whether a customer made a substantial contribution to a proceeding, we look at several things. First, we look at whether the Commission adopted one or more of the factual or legal contentions, or specific policy or procedural recommendations put forward by the customer. (§ 1802(i).) Second, we look at if the customer's contentions or recommendations paralleled those of another party and, if so, whether the customer's participation unnecessarily duplicated or materially supplemented, complemented, or contributed to the presentation of the other party or to the development of a fuller record that assisted the Commission in making its decision. (§§ 1801.3(f) and 1802.5.)

As described in § 1802(i), the assessment of whether the customer made a substantial contribution requires the exercise of judgment.

> In assessing whether the customer meets this standard, the Commission typically reviews the record, composed in part of pleadings of the customer and, in litigated matters, the hearing transcripts, and compares it to the findings, conclusions, and

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[3] No party opposed the request.

> orders in the decision to which the customer asserts it contributed. It is then a matter of judgment as to whether the customer's presentation substantially assisted the Commission.[4]

Should the Commission not adopt any of the customer's recommendations, compensation may be awarded if, in the judgment of the Commission, the customer's participation substantially contributed to the decision or order. For example, if a customer provided a unique perspective that enriched the Commission's deliberations and the record, the Commission could find that the customer made a substantial contribution. With this guidance in mind, we turn to the claimed contributions TURN made to the proceeding.

TURN claims compensation for substantial contributions to D.07-09-041 as well as to Resolution G-3372 and D.05-09-046, denying rehearing of Resolution G-3372. We address these issues separately.

3.1. D.07-09-041

The Commission initiated the backbilling investigation in response to TURN's motion as well as the number of complaints received by the Commission and issues raised in response to PG&E's Advice Letter 2250-G/2534-E. D.07-09-041 adopted most of TURN's recommendations, concluding that refunds were warranted, that the refunds should be funded by shareholders, that the refunds should not be limited due to data limitations prior to December 2002 or by a statute of limitations, and should be paid to all eligible customers identified through reasonable attempts (as proposed by TURN) to locate customers no longer with PG&E; and ordering additional remedies proposed by TURN for customers who endured termination of service for nonpayment of

[4] D.98-04-059, 79 CPUC2d 628 at 653.

unlawfully backbilled amounts. Although the Commission did not adopt TURN's proposed prospective changes to the ratemaking treatment of undercollections resulting from the backbilling limits of Rule 17.1, TURN's presentation on this issue greatly assisted the Commission in its consideration of whether ratepayers or shareholders should fund the refunds. TURN substantially contributed to D.07-09-041.

3.2. Resolution G-3372 and D.05-09-046

Although we compensate TURN for its costs related to Resolution G-3372 and D.05-09-046, we do so on the basis of TURN's substantial contribution to the backbilling investigation.

TURN cites to D.06-10-013 as standing for the proposition that work related to a substantial contribution to a resolution is compensable if the resolution addresses a similar subject matter as was at issue in a decision in a proceeding. In fact, D.06-10-013 addressed very different circumstances, and did not award compensation for contribution to a resolution on the basis that TURN suggests. D.06-10-013 addressed the issue of whether compensation is warranted for contribution to a resolution that implemented an earlier, related decision, and concluded that "[t]he ongoing work [before the Commission] of [intervenors] to ensure successful implementation of [the related decision] resulted in a substantial contribution to the decision and should be compensated." (D.06-10-013, p. 11.) Here, in contrast, Resolution G-3372 and D.05-09-046 did not implement the related D.07-09-041; rather, they preceded it.

3.3. Intervenor's Contribution Relative to Other Parties

Section 1801.3(f) states that the intervenor compensation statutes are to be administered so as to avoid unproductive or unnecessary participation that duplicates the participation of similar interests otherwise adequately represented by another party, or participation unnecessary for a fair determination of the proceeding. However, § 1802.5 provides that an intervenor's participation that materially supplements, complements, or contributes to the presentation of another party may be fully eligible for compensation if it makes a substantial contribution to the Commission order or decision.

In addition to PG&E and TURN, the Commission's Consumer Protection and Safety Division (CPSD) participated in the proceeding. Although TURN and CPSD represented overlapping interests and supported overlapping recommendations, TURN's participation did not duplicate that of CPSD. TURN carried the bulk of responsibility in testimony, hearings and briefing for ratemaking issues related to refunds. TURN made several specific recommendations adopted by the Commission that were unique and that did not overlap with CPSD's recommendations. On issues where TURN's recommendations overlapped those of CPSD's, such as the statute of limitations issue, TURN presented separate facts or authority which substantially assisted the Commission. We find that TURN's participation materially supplemented, complemented, and contributed to CPSD's presentation and made a substantial contribution to D.07-09-041.

4. Reasonableness of Requested Compensation

TURN requests $317,914.33 for its participation in this proceeding, as follows:

Work on Proceeding				
Attorney Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Robert Finkelstein	2004	18.25	$395.00	$7,208.75
Robert Finkelstein	2005	16.00	$395.00	$6,320.00
Robert Finkelstein	2006	14.75	$405.00	$5,973.75
Robert Finkelstein	2007	3.50	$435.00	$1,522.50
Michel Florio	2004	0.50	$470.00	$235.00
Michel Florio	2005	1.00	$470.00	$470.00
Michel Florio	2006	59.75	$485.00	$28,978.75
Michel Florio	2007	2.75	$525.00	$1,443.75
Hayley Goodson	2004	18.75	$190.00	$3,562.50
Hayley Goodson	2005	207.00	$190.00	$39,330.00
Hayley Goodson	2006	497.75	$195.00	$97,061.25
Hayley Goodson	2007	108.75	$210.00	$22,837.50
Victoria Hartanto	2006	46.00	$100.00	$4,600.00
Subtotal attorney fees:				**$219,543.75**
Expert Witness Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Bill Marcus	2005-4/30/06	4.09	$210.00	$858.90
Bill Marcus	5/1/06-2007	1.75	$220.00	$385.00
Greg Ruszovan	2005-4/30/06	151.39	$155.00	$23,465.45
Greg Ruszovan	5/1/06-2007	23.73	$165.00	$3,915.45

Work on Proceeding				
Attorney Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Expert Witness Fees	**Year**	**Hours**	**Hourly Rate**	**Total**
Gayatri Schilberg	2005-4/30/06	259.51	$165.00	$42,819.15
Gayatri Schilberg	5/1/06-2007	120.54	$175.00	$21,094.50
Subtotal expert witness fees:				**$92,538.45**
Expenses				$ 2,917.13
Intervenor Compensation Claim Preparation				
Attorneys	**Year**	**Hours**	**Rate**	**Total**
Robert Finkelstein	2007	2.00	$217.50	$435.00
Hayley Goodson	2005	4.00	$95.00	$380.00
Hayley Goodson	2007	20.00	$105.00	$2,100.00
Subtotal claim preparation				**2,915.00**
Total Requested Compensation				**$317,914.33**

In general, the components of this request must constitute reasonable fees and costs of the customer's preparation for and participation in a proceeding that resulted in a substantial contribution. The issues we consider to determine reasonableness are discussed below:

4.1. Hours and Costs Related to and Necessary for Substantial Contribution

We first assess whether the hours claimed for the customer's efforts that resulted in substantial contributions to Commission decisions are reasonable by determining to what degree the hours and costs are related to the work performed and necessary for the substantial contribution.

TURN documented its claimed hours by presenting a daily breakdown of the hours of its attorneys, accompanied by a brief description of each activity. The hourly breakdown reasonably supports the claim for total hours. The hours claimed for travel time are related to limited, non-routine travel by TURN's attorney and expert witness for events at which their in-person attendance was reasonably required.[5]

4.2. Intervenor Hourly Rates

We next take into consideration whether the claimed fees and costs are comparable to the market rates paid to experts and advocates having comparable training and experience and offering similar services.

TURN seeks an hourly rate of $395 for work performed by Finkelstein in 2004 and 2005. We previously approved this rate in D.05-04-014 and D.05-12-038, and adopt it here.[6] TURN seeks an hourly rate of $405 for work performed by

[5] TURN charged half of actual travel time, consistent with Commission policy of compensating reasonable travel time.

[6] TURN bases its requested 2005 rates for Finkelstein and Florio on its statement that D.05-11-031 previously approved them. TURN's statement is misleading, as D.05-11-031 did not approve any particular rates for any particular representative. Informally, TURN clarified to the ALJ that D.05-11-031 "supports" the requested rates, and suggested that no record clarification or analysis is necessary because D.07-04-010 and D.07-07-039 previously adopted the requested rates on the same showing as TURN makes here. However, D.07-04-010 adopted the rate for Finkelstein on the basis of earlier Commission approval of the same rate, and D.07-07-039 adopted the requested rate for Florio on the basis that it conforms with D.05-11-031; neither decision cites TURN's statement in its support, and we do not assume that it was sufficient to persuade the decisions' results. Nevertheless, we have identified precedent for approving the requested rates, which we cite herein. In the spirit of TURN's request, which asks for an opportunity to provide further information needed in order to adopt the requested rates, and in the interests of assisting the transparency of our decisions

Footnote continued on next page

Finkelstein in 2006. We previously approved this rate in D.06-10-018, and adopt it here. TURN seeks an hourly rate of $435 for work performed by Finkelstein in 2007. We previously approved this rate in D.07-12-026, and adopt it here.

TURN seeks an hourly rate of $470 for work performed by Florio in 2004 and 2005. We previously approved this rate in D.05-01-029 and D.06-07-011, and adopt it here. TURN seeks an hourly rate of $485 for work performed by Florio in 2006. We previously approved this rate in D.06-11-032, and adopt it here. TURN seeks an hourly rate of $525 for work performed by Florio in 2007. This rate includes the 3% cost of living increase, plus the 5% step increase generally authorized for 2007 rates in D.07-01-009. However, D.07-01-009 also provides that step increases may not result in rates above the highest rate for any given range for a given year (D.07-01-009, p. 6). We therefore approve a rate of $520, the highest rate for the range of applicable 2007 rates, for Florio's work.

TURN seeks an hourly rate of $190 for work performed by Goodson in 2004 and 2005. We previously approved this rate in D.05-01-029 and D.05-11-031, and adopt it here. TURN seeks an hourly rate of $195 for work performed by Goodson in 2006, and an hourly rate of $210 for her work performed in 2007. We previously approved these rates in D.07-12-026, and adopt them here.

TURN seeks an hourly rate of $100 for work performed by Hartanto, a law student at the University of California at Berkeley’s Boalt Hall who worked as a summer associate with TURN during 2006. We previously approved an hourly

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and speedy resolution of its requests, we advise TURN to revise its showing in its future requests consistent with the guidance given here.

rate of $100 for the work of a summer associate employed by Disability Rights Advocates in D.07-04-032, and adopt it here for Hartanto.

TURN seeks an hourly rate of $210 for work performed by Marcus, of JBS Energy, in 2005. We previously approved this rate in D.06-04-029, and adopt it here. TURN seeks an hourly rate of $220 for work performed by Marcus in 2006. We previously approved this rate in D.07-05-043, and adopt it here.[7]

TURN seeks an hourly rate of $155 for work performed by Ruszovan, of JBS Energy, in 2005 through April 30, 2006. We previously approved this rate for 2005 in D.06-10-018, and adopt it here as requested for Ruszovan's work through April 30, 2006.

TURN seeks an hourly rate of $165 for work performed by Ruszovan for work performed after May 1, 2006. This is TURN's first request for compensation for Ruszovan's work during this period. As TURN points out, this is roughly equivalent to applying the 3% cost of living increase approved for 2006 and 2007 rates in D.07-01-009. Specifically, although TURN requests $27,380.90 for Ruszovan's work based on its requested rates, using an hourly rate of $155 for 2005, and escalating it to $160 for 2006 and $165 for 2007, comes to $27,523.35, a difference of only $142. Given this minor difference, it is reasonable to approve the requested rates for Ruszovan's work.

TURN seeks an hourly rate of $165 for work performed by Schilberg, of JBS Energy, in 2005 through April 30, 2006. We previously approved this rate for 2005 in D.06-04-012, and adopt it here as requested for Schilberg's work through

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[7] More specifically, TURN requests the hourly rate of $210 for Marcus's work through April 30, 2006, and the hourly rate of $220 for Marcus's work after May 1, 2006. As all

Footnote continued on next page

April 30, 2006. TURN seeks an hourly rate of $175 for work performed by Schilberg from May 1, 2006 through 2007. We previously adopted this rate in D.07-12-026. In addition, this is roughly equivalent to applying the 3% cost of living increase approved for 2006 and 2007 rates in D.07-01-009, and reflects the actual rates JBS Energy charged TURN. Specifically, although TURN requests $63,913.65 for Schilberg's work based on its requested rates, using an hourly rate of $165 for 2005, and escalating it to $170 for 2006 and $175 for 2007, comes to $63,565.25, a difference of only $348. Given this minor difference, it is reasonable to approve the requested rates for Schilberg's work.

4.3. Productivity

D.98-04-059 directed customers to demonstrate productivity by assigning a reasonable dollar value to the benefits of their participation to ratepayers. The costs of a customer's participation should bear a reasonable relationship to the benefits realized through its participation. This showing assists us in determining the overall reasonableness of the request.

TURN's participation was productive in that the impact of that participation far exceeded fees and other costs. TURN's participation substantially contributed to the Commission ordering PG&E to refund approximately $35.3 million to customers unlawfully backbilled, to credit approximately $300,000 to customers who lost their utility service for failing to pay unlawful backbills, and to take steps to have any reference to the nonpayment of customers' closing bills related to illegal backbills removed from

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of Marcus's work was performed either in November-December 2005 or May 2006, we approve these rates on a calendar basis, consistent with our past practice.

the customers' credit records. Thus, we find that TURN's efforts have been productive.

4.4. Direct Expenses

The itemized direct expenses submitted by TURN include the following:

Attorney Travel	$40.26
Consultant Travel	$223.95
Legal Research (LEXIS)	$722.70
Deposition/Transcripts	$1,061.95
Photocopying	$807.11
Postage	$32.26
Telephone	$28.90
Total Expenses	**$2,917.13**

The cost breakdown included with the request shows the miscellaneous expenses to be commensurate with the work performed. We find these costs reasonable.

5. Award

We award TURN $317,900.58. This reflects the amount of TURN's requested compensation as set forth in the above tables, adjusted to reflect the $520 rate for Florio's work in 2007.

Consistent with previous Commission decisions, we order that interest be paid on the award amount (at the rate earned on prime, three-month commercial paper, as reported in Federal Reserve Statistical Release H.15) commencing on February 4, 2008, the 75th day after TURN filed its compensation request, and continuing until full payment of the award is made.

We remind all intervenors that Commission staff may audit their records related to the award and that intervenors must make and retain adequate accounting and other documentation to support all claims for intervenor compensation. TURN's records should identify specific issues for which it requested compensation, the actual time spent by each employee or consultant, the applicable hourly rates, fees paid to consultants, and any other costs for which compensation was claimed.

6. Waiver of Comment Period

This is an intervenor compensation matter. Accordingly, as provided by Rule 14.6(c)(6) of our Rules of Practice and Procedure, we waive the otherwise applicable 30-day comment period for this decision.

7. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner, and Hallie Yacknin is the assigned ALJ in this proceeding.

Findings of Fact

1. TURN has satisfied all the procedural requirements necessary to claim compensation in this proceeding.
2. TURN made a substantial contribution to D.07-09-041 as described herein.
3. TURN's requested hourly rates for its representatives, as adjusted herein, are reasonable when compared to the market rates for persons with similar training and experience.
4. TURN requested related expenses that are reasonable and commensurate with the work performed.
5. The total of the reasonable compensation is $317,900.58.
6. The appendix to this opinion summarizes today's award.

Conclusions of Law

1. TURN has fulfilled the requirements of §§ 1801-1812, which govern awards of intervenor compensation, and is entitled to intervenor compensation for its claimed expenses incurred in making substantial contributions to D.07-09-041.

2. TURN should be awarded $317,900.58 for its contribution to D07-09-041.

3. This order should be effective today so that TURN may be compensated without further delay.

4. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The Utility Reform Network (TURN) is awarded $317,900.58 as compensation for its substantial contributions to Decision 07-09-041.

2. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall pay TURN the total award. Payment of the award shall include interest at the rate earned on prime, three-month commercial paper as reported in Federal Reserve Statistical Release H.15, beginning February 4, 2008, the 75th day after the filing date of TURN's request for compensation, and continuing until full payment is made.

3. Application (A.) 02-11-017, A.02-09-005, and I.03-01-012 are closed.

This order is effective today.

Dated March 13, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

APPENDIX

Compensation Decision Summary Information

Compensation Decision:	D0803012	**Modifies Decision? No**
Contribution Decision(s):	D0709041	
Proceeding(s):	A0211017/I0301012/A0209005	
Author:	ALJ Yacknin	
Payer(s):	Pacific Gas and Electric Company	

Intervenor Information

Intervenor	Claim Date	Amount Requested	Amount Awarded	Multiplier?	Reason Change/Disallowance
The Utility Reform Network	11/21/07	$317,914.33	$317,900.58	no	Failure to justify hourly rate

Advocate Information

First Name	Last Name	Type	Intervenor	Hourly Fee Requested	Year Hourly Fee Requested	Hourly Fee Adopted
Robert	Finkelstein	Attorney	The Utility Reform Network	$395.00	2004	$395.00
Robert	Finkelstein	Attorney	The Utility Reform Network	$395.00	2005	$395.00
Robert	Finkelstein	Attorney	The Utility Reform Network	$405.00	2006	$405.00
Robert	Finkelstein	Attorney	The Utility Reform Network	$435.00	2007	$435.00
Michel	Florio	Attorney	The Utility Reform Network	$470.00	2004	$470.00
Michel	Florio	Attorney	The Utility Reform Network	$470.00	2005	$470.00

Michel	Florio	Attorney	The Utility Reform Network	$485.00	2006	$485.00
Michel	Florio	Attorney	The Utility Reform Network	$525.00	2007	$520.00
Hayley	Goodson	Attorney	The Utility Reform Network	$190.00	2004	$190.00
Hayley	Goodson	Attorney	The Utility Reform Network	$190.00	2005	$190.00
Hayley	Goodson	Attorney	The Utility Reform Network	$195.00	2006	$195.00
Hayley	Goodson	Attorney	The Utility Reform Network	$210.00	2007	$210.00
Victoria	Hartanto	Law Student/ Clerk	The Utility Reform Network	$100.00	2006	$100.00
Bill	Marcus	Economist	The Utility Reform Network	$210.00	2005-	$210.00
Bill	Marcus	Economist	The Utility Reform Network	$220.00	2006	$220.00
Greg	Ruszovan	Analyst	The Utility Reform Network	$155.00	2005- 4/30/06	$155.00
Greg	Ruszovan	Analyst	The Utility Reform Network	$165.00	5/1/06-2007	$165.00
Gayatri	Schilberg	Economist	The Utility Reform Network	$165.00	2005- 4/30/06	$165.00
Gayatri	Schilberg	Economist	The Utility Reform Network	$175.00	5/1/06-2007	$175.00

(END OF APPENDIX)

CPUC Decision 08-07-046 July 31, 2008
DECISION ON THE TEST YEAR 2008 GENERAL RATE CASES FOR SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY

 Date of Issuance 8/1/2008

Decision 08-07-046 July 31, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902M) for authority to update its gas and electric revenue requirement and base rates effective on January 1, 2008.	Application 06-12-009 (Filed December 8, 2006)
Application of Southern California Gas Company for authority to update its gas revenue requirement and base rates effective on January 1, 2008. (U904G)	Application 06-12-010 (Filed December 8, 2006)
Order Instituting Investigation on the Commission's own motion into the rates, operations, practices, services and facilities of San Diego Gas & Electric Company and Southern California Gas Company.	Investigation 07-02-013 (Filed February 15, 2007)

(See Appendix 11 for List of Appearances.)

DECISION ON THE TEST YEAR 2008 GENERAL RATE CASES FOR SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY

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DECISION ON THE TEST YEAR 2008 GENERAL RATE CASES FOR SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY

1. Summary

San Diego Gas & Electric Company (SDG&E) filed Application (A.) 06-12-009, a general rate case (GRC) application, and Southern California Gas Company (SoCalGas) filed A.06-12-010, also a GRC application. They are related companies with some shared services. This decision adopts for each company a Test Year 2008 revenue requirement, a mechanism for attrition adjustments until the next GRC, and performance and safety incentive mechanisms, which are reasonable and necessary to provide safe and reliable service to ratepayers.

The Test Year 2008 settlements adopted in this decision provide a gas and electric revenue requirement of $1.361 billion for SDG&E and a gas revenue requirement of $1.685 billion for SoCalGas.

Compared to SDG&E's 2007 authorized revenue requirements, this is an increase of $150 million (12.4%), in 2008, with further Post-Test Year increases for 2009 through 2011 of $41 million (3.0%), $44 million (3.1%), and $44 million (3.0%), respectively.

For SoCalGas, this is an increase of $59 million (3.6%), in 2008, with further Post-Test Year increases for 2009 through 2011 of $52 million (3.1%), $50 million (2.9%), and $53 million (3.0%), respectively.

The initial requests by SDG&E and SoCalGas were Test Year 2008 revenue requirements of $1.425 billion for SDG&E, and $1.785 billion for SoCalGas, with further increases in the subsequent five years of a proposed six-year rate cycle. The test year and post-test year settlement agreements adopted here reduced the total requested revenues by $164 million for 2008 and $213 million over the four-year rate cycle as adopted herein.

The decision requires SDG&E and SoCalGas to file another rate case for Test Year 2012 and it allows the filing of a single combined application with separate revenue requirements for each company. This decision adopts eight settlements, and rejects two others, pursuant to Rule 12 *et seq.*, between applicants and various parties which, in total, resolve nearly all contested issues.

The adopted settlements were not all-party settlements and therefore this decision resolves all objections to those settlements, with any reasonable and necessary modifications. The adopted settlements are:

1. Settlement Agreement Regarding San Diego Gas & Electric Company Test Year 2008 Revenue Requirement with the Division of Ratepayer Advocates (DRA);
2. Settlement Agreement Regarding Southern California Gas Company Test Year 2008 Revenue Requirement with DRA and The Utility Reform Network (TURN);
3. Settlement Agreement Regarding San Diego Gas & Electric Company Post-Test Year Ratemaking with DRA, TURN and the Aglet Consumer Alliance (Aglet);
4. Settlement Agreement Regarding Southern California Gas Company Post-Test Year Ratemaking DRA, TURN and Aglet;
5. Settlement Agreement Regarding Employee Safety Incentive Measure for SDG&E with Coalition of California Utility Employees;
6. Settlement Agreement Regarding Utility Workers Union of America, Local 132 Issues - A Safety Incentive for SoCalGas;
7. Settlement Agreement with Pest Control Operators - Tariff Rules for SDG&E and SoCalGas; and
8. Settlement Agreement with Disability Rights Advocates - Accessibility issues for SDG&E.

This decision rejects two other proposed settlements that are not in the public interest, and not reasonable, based on the record of the proceeding:

1. Six Year Leadership Agreement with the Greenlining Institute - on Corporate Philanthropy and Diversity of SDG&E and SoCalGas, with The Greenlining Institute, and
2. Settlement Agreement Regarding Local 483 Issues - for SoCalGas.

This decision also resolves the remaining contested issues addressing various incentive mechanisms on safety and reliability. Finally, this decision finds that the effective date for the change in revenue requirement is January 1, 2008, which resolves the one issue identified in Decision 07-12-053. These proceedings are closed.

2. Procedural Background

A January 2, 2007 ruling consolidated the applications pursuant to Rule 7.4. DRA, Disability Rights Advocates, PCOC, Southern California Generation Coalition, and TURN timely filed protests. The Commission preliminarily categorized these matters as ratesetting and requiring hearings in Resolution ALJ 176-3185. The categorization of these proceedings is determined herein to be ratesetting. A prehearing conference (PHC) was held on February 9, 2007, for a discussion on the scope of the proceeding, guidelines on discovery,[1] lead counsel to reduce duplication,[2] scheduling, and a mandatory effort for settlement. An assigned Commissioner's scoping ruling was subsequently issued on February 27, 2007. The scoping ruling confirmed that this was a ratesetting proceeding and evidentiary hearings were necessary. There were 13 days of

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[1] For discovery, the parties preferred that any deadlines be more "guidelines" than "rules," thus no specific limits were set.

[2] TR., p. 10, ff.

SoCalGas only) or DRA related to the calculation of SoCalGas or SDG&E depreciation expense;

e. Whether or not, as a matter of policy, the CPUC should consider the proposals raised by TURN (with respect to SoCalGas only) or DRA related to the calculation of SoCalGas or SDG&E working cash expense, including whether Customer Deposits should be considered as a source of working cash; and

f. Whether or not, as a matter of policy, the CPUC should consider the proposals raised by TURN related to the SoCalGas Employee Stock Ownership Plan and its relationship to the calculation of SoCalGas' income tax expense.

5.2.1. Authorized Non-Utility Payment Locations and Branch Offices

The bilateral settlement with Disability Rights Advocates, discussed elsewhere in this decision, provides for studies and certain limitations on branch office closures and new authorized payment locations. As discussed below, we still have concerns which we find compelling after considering, for example, cross examination by Greenlining and TURN which showed there had not been a careful study on the impacts to low-income customers. Thus, we adopt the settlement with the further guidance here on branch offices generally and authorized non-utility payment locations. We go further than the settlement and place a moratorium on branch office closures and new pay-day lender payment locations.

We find that the proposal to close branch offices is problematic for low-income customers. We, therefore, find that all existing branch offices should remain open but that applicants may separately apply to close individual offices in the future or revisit the issue in the next GRC. The reality is that some customers are more expensive to service than others: we cannot presume all to have internet bill-paying capacity or even checking accounts. Therefore, we must find a way to serve these customers' needs for bill payment, customer service, and information. The traditional branch offices serve these functions.

5.2.2. Authorized Non-Utility Payment Locations

We find that "payday lenders" or check-cashing outlets are problematic locations for customers to pay their bills. We, therefore, impose a moratorium on further pay-day lender non-utility authorized payment locations. Applicants argue that these businesses are regulated by the state and they are willing, unlike many other businesses, to undertake payment functions. As noted above, some customers are harder to serve and branch offices meet their needs. We accept applicants' testimony on the very limited number of customers who use branch offices or payment locations. Nevertheless, we agree that these payday lender businesses are problematic because of the potential for customers to enter into legal but costly loans in the process of paying their utility bills. We, therefore, will place a moratorium on any further contracts with payday lenders.[12] We invite applicants to work with parties and develop other options to serve these customers' needs. SDG&E and SoCalGas may bring an application at any time to propose a comprehensive solution to the problems of business office closures and payment locations, or defer any further action to the next GRC.

[12] Disability Rights Advocates commented on the proposed and alternate decision that a restriction on new pay-day lenders would not require any modification to the settlement which is silent on the particular types new payment locations. (Comments, p. 3.)

recovery of generation related A&G expense and general plant overheads from DA customers in its ERRA proceedings.

The proposals to directly assign the three generation related A&G departments to generation will not be adopted. We agree with SCE's arguments that these departments also perform distribution-related tasks, and the proposal is one-sided in that it does not consider any other A&G organizations that may be weighted more heavily to the distribution function. To implement the proposal properly, all A&G costs should first be analyzed for direct assignment and the remaining indirect costs allocated to functions. However, this would be contrary to the current methodology for allocating A&G costs to the FERC jurisdictional transmission function and inconsistent with our actions in D.03-08-062 in A.01-02-030.[31]

10. Transmission and Distribution Expenses

10.1. Stipulation on Priority 5 Maintenance

SCE's current maintenance priority system uses a five-point numerical rating scheme. Priority 1 corrections require immediate attention because they pose the greatest risk to public safety or system reliability. Maintenance items rated Priority 2 through Priority 4 pose much less risk to public safety or system reliability and are scheduled for repair according to the specific item and the degree of degradation. Priority 5 items are those that pose a greater safety risk to the employees performing the repair than they do to the

[31] In that decision, the Commission accepted the use of FERC's labor allocator methodology to assign A&G and general plant costs to the transmission function and essentially rejected a previous Commission adopted methodology by which directly assignable costs were first assigned to functions and indirect costs were then allocated to functions by a multi-factor.

public or to system reliability if the maintenance is left unaddressed. An example of a Priority 5 maintenance item is a missing or not completely legible high voltage sign, which poses no significant increased risk to public or employee safety but does put an employee at risk when repairing the signage.

Currently, Priority 5 maintenance is performed on an opportunity basis. When a crew is scheduled to work on a pole, they will repair all Priority 5 maintenance items at that work level and below. D.04-04-065 issued in April 2004 in SCE's Line Maintenance OII (I.01-08-029) directed SCE, in consultation with the Consumer Protections and Safety Division (CPSD) to, among other things, "[a]chieve a more defined period within which system problems are repaired."[32] Based on its experience up to, during and subsequent to the Line Maintenance OII, SCE has concluded that compliance with that direction could be interpreted to require that the Company establish date certain criteria for all Priority 5 maintenance items. Although the Commission in D.04-04-065 did not absolutely mandate the termination of opportunity maintenance or specify the time frame in which it expects Priority 5 items to be repaired, that decision does ask that the amount of time for making system repairs be decreased.

SCE developed three time-dependent scenarios (5-year, 6-year and 10-year) for moving Priority 5 work from an opportunity-based approach to the Commission-envisioned "defined period" approach, and analyzed which scenario would be best for SCE and it customers. SCE's application request included $40,800,000 per year to perform that work over a six-year period.

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[32] D.04-04-065, (*mimeo.*), p. 22.

SCE's application request for Priority 5 maintenance was opposed by both DRA and TURN. In its testimony, DRA recommended that SCE continue its current overhead distribution maintenance priority system. Specifically, Priority 5 maintenance items should continue to be repaired as opportunity maintenance. According to TURN, D.04-04-065 does not require SCE to change its Priority 5 maintenance activities in this rate case, and SCE has not complied with the directives of D.04-04-065 to first consult with CPSD and to exhaust other alternatives to accelerated maintenance of all Priority 5 conditions. In its testimony, TURN recommended that the Commission should authorize SCE to continue opportunity based maintenance of Priority 5 conditions until this issue is separately resolved. Even if the Commission were to authorize a change in Priority 5 maintenance, TURN argued SCE's requested budget is excessive and unreasonable.

The issue of Priority 5 maintenance has evolved during this proceeding. Since May 28, 2004, management representatives and staff of CPSD and SCE have worked together in compliance with the Commission's directives in D.04-04-065. As of August 13, 2005, CPSD and SCE have agreed on a set of principles governing a refined priority maintenance system for correcting violations of General Order (GO) 95 and GO 128. Those principles are set forth in a Memorandum of Understanding (MOU).[33] The MOU would have SCE continue its current opportunity maintenance practice for correction of Priority 5 items until such time as the Commission reviews, approves and authorizes funding for a revised maintenance program to be proposed in SCE's next GRC.

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[33] The MOU was identified as Late-Filed Exhibit 166 and received in evidence by ruling dated August 30, 2003.

In its opening brief, SCE revised its primary recommendation regarding Priority 5 maintenance, consistent with these MOU principles.

On August 29, 2005, SCE, DRA and TURN filed a stipulation regarding the Priority 5 issue. By the stipulation, SCE will withdraw its requested funding for acceleration of Priority 5 maintenance on a date-certain basis, on condition that SCE, DRA and TURN recommend that the Commission: (1) find SCE's current opportunity maintenance approach to Priority 5 maintenance to be compliant with D.04-04-065, and (2) direct SCE to continue its current opportunity maintenance practice for correction of Priority 5 items until such time as the Commission authorizes a change in Priority 5 maintenance practices. Consistent with the MOU, SCE would not propose any such change prior to its next GRC. SCE, DRA and TURN identified the stipulation proposal as their primary Priority 5 recommendation in their respective reply briefs filed on September 2, 2005.[34]

10.2 Discussion

By establishing (1) principles for a refined priority maintenance system for correcting violations of GO 95 and GO 128, and (2) a timeline for the development, testing and implementation of these principles, the SCE/CPSD MOU demonstrates a commitment to comply, and progress in complying, with directives in D.04-04-065 regarding SCE's remedial actions regarding such violations. Due to the extent of the costs needed to correct all such identified violations, it is important to ensure that the safety and reliability concerns are addressed in a cost effective manner. The MOU also appears to have this prime consideration in mind.

For the purposes of this GRC, we find that the MOU provides a reasonable basis for SCE and CPSD to address GO 95 and GO 128 violation issues. It is reasonable for SCE and CPSD to continue to work out details for establishing and implementing the new maintenance program. When there is final agreement on the new program, it can be presented for the Commission's consideration and adoption. Since the MOU envisions the implementation and

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[34] If the Commission were to decline adoption of this primary recommendation, SCE, DRA and TURN would revert to their recommendations and arguments regarding ratepayer funding of SCE's accelerated Priority 5 maintenance proposal.

transition period for the new maintenance priority system to begin with SCE's next test year, for this test year 2006 GRC cycle, it is reasonable for SCE to continue its current maintenance program. Therefore, there is no need to increase funding for Priority 5 maintenance at this time. For the 2006 – 2008 interim period, as long as SCE and CPSD are meaningfully engaged in developing the new maintenance priority system, we will consider SCE's opportunity maintenance approach to Priority 5 maintenance to be compliant with D.04-04-065.

SCE, DRA and TURN are the only parties that addressed the Priority 5 issue, and, with the filing of the stipulation, agree on how to proceed with this issue. The stipulation, as described above, is generally consistent with the development of a new maintenance program, as envisioned in the SCE/CPSD MOU. It reasonably resolves the Priority 5 issue in this proceeding, is consistent with law, is in the public interest, and will be approved.

10.3 Account 560.100 – Advanced Technologies for Transmission System

For Account 560.100, SCE is requesting a total of $8,390,000 for the test year. Included in that amount is $4,100,000 for eight advanced technology projects.

DRA recommends zero funding for these projects arguing that SCE has not quantified any cost savings that justify inclusion of the costs; and SCE has not shown that the historical spending level is insufficient to meet the system function needs for this sub-account.

10.4 Discussion

In general, budgets or incremental budgets to historic recorded amounts must be explained and justified. Studies which show that short-term and/or long-term benefits exceed costs could provide persuasive justification for

SCE's incremental budgeted costs. However, in this case, SCE indicates that cost benefits/savings estimates are typically developed as a result of (not prior to) these types of programs. Therefore, while SCE can provide cost information, the benefits/savings associated with these T&D advanced technology projects or programs are not known.

The descriptions of the potential benefits of the projects provide general information but there is not sufficient information to determine whether the costs are justified in either the short or long term. With this type of analysis and showing it is possible to explicitly include associated costs in rates but it is not possible to explicitly reflect any of the associated benefits or savings, whatever they may ultimately be, in rates for this rate case cycle. This imbalance is troubling. In general, it is our obligation to consider both the costs and, if applicable, the benefits/savings of utility proposals. If the benefits/savings are ultimately small when compared to costs, the proposal should probably not be implemented or included in rates. If the benefits/savings are substantial, it would be reasonable to include both the costs and benefits/savings in determining rates. For the advanced technology programs/projects, the lack of information regarding benefits/savings precludes us from making such determinations.

In this decision, we are authorizing significant increases in T&D O&M and capital expenditures. How the potential benefits of the advanced technology programs/projects relate to SCE's proposals for increased spending is not clear. Whether the advanced technology spending results in the modification of any future spending related to T&D costs has not been shown. SCE states,

Decision 08-09-038 September 18, 2008

DECISION REGARDING PERFORMANCE BASED RATEMAKING (PBR),

FINDING VIOLATIONS OF PBR STANDARDS, ORDERING REFUNDS, AND IMPOSING A FINE

Decision 08-09-038 September 18, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Investigation on the Commission's Own Motion into the Practices of the Southern California Edison Company to Determine the Violations of the Laws, Rules, and Regulations Governing Performance Based Ratemaking, its Monitoring and Reporting to the Commission, Refunds to Customers and Other Relief, and Future Performance Based Ratemaking for this Utility.	Investigation 06-06-014 (Filed June 15, 2006)

(Appearances are in Appendix A)

DECISION REGARDING PERFORMANCE BASED RATEMAKING (PBR), FINDING VIOLATIONS OF PBR STANDARDS, ORDERING REFUNDS, AND IMPOSING A FINE

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DECISION REGARDING PERFORMANCE BASED RATEMAKING (PBR), FINDING VIOLATIONS OF PBR STANDARDS, ORDERING REFUNDS, AND IMPOSING A FINE

This decision concludes that Southern California Edison Company (SCE) employees and management manipulated and submitted false customer satisfaction data, and the data was used to determine Performance Based Ratemaking (PBR) customer satisfaction rewards for a period of seven years. Therefore, SCE is ordered to refund to its ratepayers all $28 million in PBR customer satisfaction rewards it has received and forgo an additional $20 million in rewards that it has requested. The decision also finds that SCE submitted false and misleading health and safety data, and the data was used to determine PBR health and safety rewards for a period of seven years. Therefore, SCE is ordered to refund to its ratepayers all $20 million in PBR health and safety rewards it has received and forgo an additional $15 million in rewards that it has requested. The decision further concludes that SCE should refund the portion of its 2003 to 2005 revenue requirement related to the utility's Results Sharing program that was affected by fraudulent data, which the decision finds to be $32,714,000. Finally, the decision orders SCE to pay a fine of $30 million for violations of the Public Utilities Code.

1. Background of Performance Based Ratemaking

In Decision (D.) 95-12-063 as modified by D.96-01-009, the Commission introduced Performance Based Ratemaking (PBR) as an alternative to the prevailing model of cost-of-service regulation of the regulated investor owned utilities. We believed existing cost-of-service regulation had become too complex to allow us to regulate utilities effectively. Our goal was to have a regulatory process that encourages utilities to focus on their performance, reduce operational costs, increase service quality, and improve productivity. At the same time, we had to ensure that safety, quality of service, and reliability were not compromised. We believed that PBR could accomplish those objectives by providing clear signals to utility managers with respect to their business decisions and by helping them make the transition from a tightly regulated structure to one that is more competitive. Under PBR, utility performance is measured against established benchmarks. Superior performance, above the benchmark, would receive financial rewards, and poor performance would result in financial penalties to the shareholders. By providing financial incentives to utilities we expected they would be encouraged to operate more efficiently, reliably, and safely to maximize their profits. We wanted to seek new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations.

In 1993 SCE filed Application (A.) 93-12-029 proposing a PBR mechanism. While A.93-12-029 was pending, we issued D.95-12-063 and relied on standards adopted in D.95-12-063 in our consideration of A.93-12-029. The result was D.96-09-092, which established the PBR metrics for SCE, which form the basis for this investigation. In D.96-09-092, we adopted PBR standards for both rate and service incentive mechanisms. In this decision, we are concerned with service incentive standards.

In regard to service, we created three categories: service reliability, customer satisfaction, and health and safety. In this decision, we are concerned only with customer satisfaction and health and safety; service reliability has been deferred to the next phase of this investigation. The incentive mechanisms we are investigating are (1) customer satisfaction, as measured by third party surveys and, (2) employee health and safety, measured by the number of first aid incidents and lost time incidents.

1.1. Customer Satisfaction Standard

The customer satisfaction standard includes both rewards and penalties in four areas: field services, local business offices, telephone centers, and service planning. Customer satisfaction for PBR purposes is measured on a scale of 1 to 5+, with 1 being low. The customer satisfaction reward and penalty was based on the percentage of scores that were either 5 or 5+. The customer satisfaction incentive had a 64% benchmark (*i.e.*, 64% of scores equal to 5 or 5+), a dead band of plus or minus 3%, and a 5% reward and penalty band in which the reward or penalty increases $2 million for each percentage point change in the average result. The maximum customer satisfaction reward or penalty is $10 million per year. To provide an incentive to avoid degradation in any one of the four areas, we adopted a floor penalty in the event customer satisfaction results decreased below 56% in any one of the four areas.

In D.02-04-055, we extended and modified SCE's PBR mechanism. The customer satisfaction incentive mechanism benchmark was increased from 64% to 69%, by averaging the then most recent nine years of survey results. That standard applied to customer satisfaction survey results for 2002 and 2003. Figure 1 summarizes the operation of SCE's customer satisfaction incentive mechanism.

Figure 1
Operation of PBR Customer Satisfaction Incentive Mechanism (1997-2003)

Reward Calculation (5&5 +) Average of 5/5+ percentage for 4 categories • Planning • Phone Center • Field Delivery • APA/Business Offices	1997 - 2001 Reward 68% - 72% $2 - $10 million Dead Band Penalty 60% - 56% ($2) – ($10) million	2002 - 2003 Reward 73 - 77% $2 - $10 million Dead Band Penalty 65% - 61% ($2) – ($10) million
Floor Penalty - Within any one category, penalty assessed if 5&5 + percentage less than 56%. - If floor penalty, reward not allowed.	Penalty 55% - 51% ($2)-($10) million	Penalty 55% - 51% ($2)-($10) million
Bottom 2 Categories (1&2) - If average 1&2 percentage for 4 categories is greater than 10% then any rewards are voided. - No separate penalty assessed.	Voids any rewards	Voids any rewards

1.2. Employee Health and Safety Standard

The PBR employee health and safety standard was established in D.96-09-092 using historical first aid and Occupational Safety and Health Administration (OSHA)-recordable incident data for the period from 1987 to 1993. Based on that data, the benchmark was set at 13.0 injuries and illnesses (first aid and OSHA-recordable incidents) per 200,000 hours worked with a dead band of +/-0.3. The PBR standard was revised in 2002 following D.02-04-055 to use the most recent seven years of data and a new standard was set at 9.8 injuries and illnesses per 200,000 hours worked with a dead band of +/-0.3. In 2003, again, the most recent seven years of data was used to create a standard of 8.6 injuries and illnesses per 200,000 hours worked with a dead band of +/-0.3. Results above or below the dead band would result in rewards or penalties.

Decision 09-03-022 March 12, 2009
DECISION GRANTING REQUEST OF THE UTILITY REFORM NETWORK FOR INTERVENOR COMPENSATION FOR SUBSTANTIAL CONTRIBUTION TO DECISION 08-09-038

Decision 09-03-022 March 12, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Investigation on the Commission's Own Motion into the Practices of the Southern California Edison Company to Determine the Violations of the Laws, Rules, and Regulations Governing Performance Based Ratemaking, its Monitoring and Reporting to the Commission, Refunds to Customers and Other Relief, and Future Performance Based Ratemaking for this Utility.	Investigation 06-06-014 (Filed June 15, 2006)

DECISION GRANTING REQUEST OF THE UTILITY REFORM NETWORK FOR INTERVENOR COMPENSATION FOR SUBSTANTIAL CONTRIBUTION TO DECISION 08-09-038

Claimant: The Utility Reform Network	**For contribution to Decision 08-09-038**
Claimed ($): $107,491	**Awarded ($): $96,715 (10% reduction)**
Assigned Commissioner: Peevey	**Assigned ALJ: Barnett**

PART I: PROCEDURAL ISSUES

A. Brief Description of Decision: Decision (D.) 08-09-038 requires Southern California Edison Company (SCE) to refund or forego $48 million in Performance-Based Ratemaking (PBR) customer satisfaction incentives and $35 in PBR safety incentives. The decision requires SCE to refund $32.714 million in money collected for results sharing compensation related to fraudulent PBR results, and orders SCE to pay a fine of $30 million. The decision agrees that SCE should refund or forego all customer satisfaction incentives even though Phase 1 focused on only a portion of the customer satisfaction mechanism. D.08-09-038 finds that SCE management knew of the data falsification and manipulation.

B. Claimant must satisfy intervenor compensation requirements set forth in Public Utilities Code §§ 1801-1812:

	Claimant	CPUC Verified
Timely filing of notice of intent to claim compensation (§ 1804(a)):		
1. Date of Prehearing Conference:	July 25, 2006	**Yes**
2. Other Specified Date for NOI:	n/a	
3. Date NOI Filed:	August 24, 2006	**Yes**
4. Was the notice of intent timely filed?		**Yes**
Showing of customer or customer-related status (§ 1802(b)):		
5. Based on ALJ ruling issued in proceeding number:	I.06-06-014	**Yes**
6. Date of ALJ ruling:	11/15/2006	**Yes**
7. Based on another CPUC determination (specify):		
8. Has the claimant demonstrated customer or customer-related status?		**Yes**
Showing of "significant financial hardship" (§ 1802(g)):		
9. Based on ALJ ruling issued in proceeding number:	I.06-06-014	**Yes**
10. Date of ALJ ruling:	11/15/2006	**Yes**
11. Based on another CPUC determination (specify):		
12. Has the claimant demonstrated significant financial hardship?		**Yes**
Timely request for compensation (§ 1804(c)):		
13. Identify Final Decision	D.08-09-038	**Yes**
14. Date of Issuance of Final Decision:	September 23, 2008	**Yes**
15. File date of compensation request:	November 24, 2008	**Yes**
16. Was the request for compensation timely?		**Yes**

PART II: SUBSTANTIAL CONTRIBUTION

A. In the fields below, describe in a concise manner Claimant's contribution to the final decision **(*see* § 1802(i), § 1803(a) & D.98-04-059) (For each contribution, support with <u>specific reference</u> to final or record.)**

Contribution	Citation to Decision or Record	Showing Accepted by CPUC
1. Refund of entire $48 million customer satisfaction reward due to performance in planning organization – TURN provided expert analysis showing that poor performance within just one category (planning) would negate all customer satisfaction awards due to the "minimum floor penalty" provision of the PBR mechanism. Testimony of Schilberg, Exh. 75, pp. 14-17. TURN also provided policy testimony against allowing SCE to earn any customer satisfaction rewards. Testimony of Finkelstein, Exh. 74. TURN also provided expert testimony showing that the penalty provisions of the PBR mechanism could result in net penalties of $24 million due to poor performance in just the planning section. Exh. 75, pp. 16-17; Exh. 76, p. 17. TURN provided policy testimony supporting the imposition of the maximum possible $70 million in PBR penalties.	D.08-09-038, pp. 51 – 54 (esp. p. 53). The Decision agrees with DRA and TURN that SCE should forego and refund all $48 million for customer satisfaction. Agrees that "Even if we were to find no manipulation and falsification in Phone Centers and Field Delivery we could not permit a company found to have falsified and manipulated customer satisfaction data to retain $33.6 million of customer satisfaction awards." Agrees that "all PBR customer satisfaction rewards could be forfeit due to poor performance in just the planning and meter reading departments. The floor penalty mechanism of the incentive mechanism could result in a complete refund of the $48 million of rewards, because the mechanism has as an integral component the prevention of deterioration in all four areas." The Decision rejects a PBR penalty as "too speculative." (D.08-09-038, p. 93.)	**Yes**
2. Extent of data manipulation – TURN analyzed record and employee data to show that manipulation was widespread and occurred in 75% of the district offices. Exh. 76, pp. 9-10, TURN showed that eliminating potential negative scores would have	Agrees that "We find that data manipulation and falsification were pervasive throughout the Design Organization and most, if not all, district offices." (D.08-09-038, pp. 18-23.) Agrees that "Both the investigation and the testimony show that these	**Yes**

impacted survey results and was not captured in SCE's analysis of direct fraud. (Exh. 76, pp. 4-7.)	planners knew what would cause Maritz to reject a number and they used that knowledge to screen out customer interactions that might result in negative customer satisfaction surveys." (D.08-09-038, p. 22).	

B. Duplication of Effort **(§§ 1801.3(f) & 1802.5):**

	Claimant	CPUC Verified
a. Was DRA a party to the proceeding? (Y/N)	**Y**	**Yes**
b. Were there other parties to the proceeding? (Y/N)	**Y**	**Yes**
c. If so, provide name of other parties: CPSD, Greenlining, UWUA		**Yes**
d. Describe how you coordinated with DRA and other parties to avoid duplication or how your participation supplemented, complemented, or contributed to that of another party: TURN coordinated explicitly with CPSD and DRA to determine the primary issues covered by CPSD and DRA. As a result, TURN focused our expert testimonies and analyses on the issue of "invalid numbers" and other potential forms of falsification and manipulation of the customer satisfaction data sent from SCE's offices to the survey firm. TURN was the only party that independently analyzed the customer satisfaction survey records collected by SCE's survey firm to determine the potential level of direct data fraud and manipulation. TURN also analyzed the extent of potential fraud by conducting analyses of results from different offices. TURN rebutted the analyses conducted by SCE witnesses Silsbee, Berk and others. TURN also provided analysis concerning the potential impact of fraud and manipulation within the planning category on customer satisfaction results due to the nature of the incentive mechanism which averaged results from four categories but with performance floors within each category. TURN explicitly coordinated with CPSD, DRA and Greenlining so as to minimize potential duplication of work. Thus, TURN did not at all address health and safety issues, which were covered by CPSD, DRA and UWUA. TURN conducted no independent analyses concerning management knowledge, though TURN reviewed information presented by CPSD. DRA addressed the issue of refunding results sharing compensation, and TURN only provided legal support in briefs on this issue. Likewise, Greenlining provided expert testimony concerning proper survey techniques, and TURN only provided additional support in briefs concerning the issue of "selling the survey."		**Yes**

C. Additional Comments on Part II (use line reference # or letter as appropriate):

#	Claimant	CPUC	Comment
	X		Please note that the Decision does not specifically identify parties' positions where similar to CPSD. ("Rather than discuss each party's position on each issue, we discuss primarily CPSD's position and refer to other parties when there is a significant difference." p. 9.) While TURN's recommendations were similar to those of the CPSD and/or DRA, TURN provided independent (and the only) analysis of the "invalid records" numbers from the customer satisfaction survey records provided by SCE to Maritz. TURN also provided analysis documenting the geographic extent of data fraud and manipulation within district offices.
	X		TURN requests full compensation for our time, consultant expenses and direct expenses. The Commission adopted TURN's major recommendation (a refund of the entire $48 million in customer satisfaction rewards), though the Commission did not adopt TURN's recommendation for a PBR penalty of $14-70 million. The analyses conducted by TURN's witness Schilberg supported both recommendations. TURN notes that participating in this proceeding required a significant expenditure of resource both to review the underlying documents prepared by CPSD and SCE, as well as to conduct the detailed analysis of customer satisfaction survey records. It would be difficult to allocate separately time devoted to the question of the appropriate amount of PBR refund versus PBR penalty.

PART III: REASONABLENESS OF REQUESTED COMPENSATION

A. General Claim of Reasonableness (§§ 1801 & 1806):

Concise explanation as to how the cost of claimant's participation bears a reasonable relationship with benefits realized through participation (include references to record, where appropriate)	CPUC Verified
This proceeding resulted in direct ratepayer benefits of approximately $145 million. TURN's participation was focused on the $48 million in claimed PBR rewards for customer satisfaction. TURN worked cooperatively with CPSD, DRA and Greenlining on this issue. TURN notes that the CPSD originally proposed that about $14.1 million of the customer satisfaction reward be ordered returned in this Phase of the proceeding. TURN and DRA argued for a full refund based on a) selling the survey, and b) floor penalty impacts of the PBR mechanism. *See*, D.08-09-038, p. 51-54. TURN's collaboration with DRA can thus be credited for a portion of the additional $34 million in customer satisfaction refunds ordered in this Phase of the proceeding. Even assuming TURN can claim credit for only 25% of that amount, the compensation requested here represents approximately 1% of $8.5 million in refunds attained.	**Yes**

B. Specific Claim:

CLAIMED						CPUC AWARD			
ATTORNEY AND ADVOCATE FEES									
Item	**Year**	**Hours**	**Rate**	**Basis for Rate***	**Total**	**Year**	**Hours**	**Rate**	**Total**
Marcel Hawiger	2006	137.5	$280	D.06-10-018, p. 39.	$38,500	2006	132.5	280	$37,100
Marcel Hawiger	2007	70.5	$300	D.07-12-026, p. 24.	$21,150	2007	48.97	300	$14,691
Marcel Hawiger	2008	4.25	$325	D.08-08-027, p. 5.	$1,381	2008	4.25	325	$1,381
Robert Finkelstein	2006	9	$405	D.06-10-018, p. 30.	$3,645	2006	9.0	405	$3,645
Robert Finkelstein	2007	2.5	$435	D.07-12-026, p. 24.	$1,088	2007	2.5	435	$1,088
Hayley Goodson	2007	1.5	$210	D.07-12-026, p. 24	$315		Waived		
				Subtotal:	***$65,764***[1]			***Subtotal:***	57,905
EXPERT FEES									
Item	**Year**	**Hours**	**Rate $**	**Basis for Rate***	**Total**	**Year**	**Hours**	**Rate**	**Total**
Gayatri Schilberg	2006[2]	151.61	185	D.08-08-024 (A.07-04-009 -- PG&E AC Cycli)	$28,048	2006	137.7	185	$25,475
Gayatri Schilberg	2007	29.17	175	D.07-12-026, p. 25	$5,105	2007	27.17	175	$4,755
Greg Ruszovan	2006	49.98[3]	165		$7,092	2006	42.98	165	$7,092
				Subtotal:	**$40,244**			***Subtotal:***	$37,322
OTHER FEES **Describe here what OTHER HOURLY FEES you are claiming (paralegal, travel, etc.):**									
Item	**Year**	**Hours**	**Rate**	**Basis for Rate***	**Total**	**Year**	**Hours**	**Rate**	**Total**
[Person 1]									
				Subtotal:				***Subtotal:***	
INTERVENOR COMPENSATION CLAIM PREPARATION ** **SEE ATTACHMENT 2 FOR DETAILS ON ATTORNEY TIME ALLOCATION**									
Item	**Year**	**Hours**	**Rate**	**Basis for Rate***	**Total**	**Year**	**Hours**	**Rate**	**Total**
Marcel	2006	.5	140	D.06-10-018, p. 39	$70	2006	.5	140	$70

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[1] TURN indicates that it voluntarily waives Goodson's time in 2007, but inadvertently includes these fees in its claim. In calculating the final award, we exclude this amount ($315.00).

[2] In its request, TURN has inadvertently categorized Schilberg's hours for 2006 as 2007 work and her 2007 hours as 2006 work. We correct this mistake here.

[3] Timesheets submitted for TURN's expert Ruszovan's total his hours as 42.98, but TURN mistakenly requests compensation of 49.98 hours. We correct this error in calculating our award.

Hawiger									
Marcel Hawiger	2008	7.5	163	D.08-08-027, p. 5	$1219	2008	7.5	163	$1,223
				Subtotal:	***$1289***			***Subtotal:***	***$1,293***

COSTS					
#	**Item**	**Detail**	**Amount**	**Total Hourly Compensation**	**$96,520**
	Xeroxing	*See* Attach. 4	$73.60		$73.60
	Postage/FedEx	*See* Attach. 4	$19.72		$19.72
	Phone/Fax	*See* Attach. 4	$15.43		$15.43
	Auto/Park/Tolls	*See* Attach. 4. Expert witness travel for hearings.	$85.76		$85.76
		Subtotal:	**$194.51**	***Subtotal:***	$**194.51**
		TOTAL REQUEST $:	**$107,491.31**	**TOTAL AWARD $:**	**$96,715**

When entering items, type over bracketed text; add additional rows as necessary.
*If hourly rate based on CPUC decision, provide decision number; otherwise, attach rationale.
**Reasonable claim preparation time typically compensated at ½ of preparer's normal hourly rate.

C. Attachments or Comments Documenting Specific Claim:

Attachment or Comment #	Description/Comment
Attachment 1	**Certificate of Service**
Attachment 2	Time sheets for attorneys showing coded time entries. TURN has grouped our contributions to D.08-09-038 into two issue categories, as shown in TURN's hourly breakdown of activities in Attachment 2, in addition to certain standard activity codes for non-issue specific work. The two issue categories are "policy," for work related to general policy issues concerning performance-based ratemaking (PBR) and proper remedies for the types of activities discovered in this investigation; and "CS" for work related to customer satisfaction PBR performance and the calculation of customer satisfaction survey results. The other categories of codes concern time spent on tasks that are fundamental to participation in a proceeding that cannot be allocated to specific issues (GP), time spent participating in hearings that was not allocable to specific issues (GH), and time spent on purely procedural matters (Proc).
Attachment 3	Time sheets for expert consultant work.
Attachment 4	Direct expense details.
Comment 1	**Basis for 2006 Rate for Greg Ruszovan** TURN requests an hourly rate of $165 for work Ruszovan performed in 2006. This is the same rate that JBS Energy billed TURN for his work during this period. The Commission authorized an hourly rate for Ruszovan of $155 for 2005. (D.06-10-018, p. 40.) The Commission authorized the same rate for Ruszovan as for Nahigian, another expert witness from JBS Energy, Inc., for 1999, 2000, 2001 and 2005. The Commission has approved an hourly rate of $165 for Nahigian's work in

	2006. (D.07-12-026, p. 25.) This is the first proceeding in which TURN requests compensation for Ruszovan for work performed in the second half of 2006. TURN requests that the Commission authorize an hourly rate of $165 for Ruszovan, an increase of 6.5%. Ruszovan is the firm's Senior Energy Analyst, with over 16 years of experience in energy conservation, advanced computer analysis, database programming and utility production simulation modeling. Since joining JBS Energy in 1989, Ruszovan has performed energy-related computer analysis of utility operations, energy data analysis, and major utility customer data base design and development. He has designed and developed a multi-relational database, including a customized data entry program for each major utility, to process and analyze individual facility energy use data. He has built models to integrate analysis of hourly market pricing data and hourly load data for individual customers or customer classes. He has provided consulting services on computer systems, both in hardware design and software operation, for a variety of clients and for the internal operations of JBS. The Commission should use the $165 rate for Ruszovan's work in 2006 for two reasons. First, this is the rate JBS Energy billed TURN, as well as other fee-paying clients, for his work during that year. In the absence of any evidence that it is not a reasonable rate or one that is consistent with market rates for similarly trained and experienced consultants, the Commission should award compensation using the billed rate. Using something less than that only serves to penalize the consultant's firm or the intervenor by creating a shortfall that must be borne by at least one of those two parties. Such a shortfall is inconsistent with Section 1801.3(b) of the Pub. Util. Code. Second, in light of the fact that the Commission recognized that the similarity of training and experience between Nahigian and Ruszovan warranted identical hourly rates from 1999 through 2001 and in 2005, there is no reason to abandon this logic in 2006 only because Ruszovan has not conducted work on behalf of TURN in other proceedings. The Commission should use the requested $165 hourly rate for his work in 2006.
Comment 2	TURN does not see compensation for 0.5 hours of Florio's time shown in Attachment 2.
Comment 3	TURN does not seek compensation for 1.58 hours of Schilberg's time in 2008 shown in Attachment 3.
Comment 4	TURN does not seek compensation for 1.5 hours of Goodson's time in 2007, shown in Attachment 2.

D. CPUC Disallowances & Adjustments (CPUC completes):

#	Reason
M. Hawiger	2006 totals reduced 5 hrs for excessiveness. 2007 hrs reduced 21.53 hrs-excessiveness and duplication.
G. Schilberg	2006 hrs reduced 13.88 hrs for excessiveness and duplication. 2007 hours reduced 2.0 hrs for excessiveness.

PART IV: OPPOSITIONS AND COMMENTS

Within 30 days after service of this claim, Commission Staff or any other party may file a response to the claim (*see* § 1804©)

(CPUC completes the remainder of this form)

A. Opposition: Did any party oppose the claim (Y/N)?	**No**

If so:

Party	Reason for Opposition	CPUC Disposition

B. Comment Period: Was the 30-day comment period waived (*see* Rule 14.6(c)(6)) (Y/N)?	**Yes**

If not:

Party	Comment	CPUC Disposition

FINDINGS OF FACT

1. Claimant has made a substantial contribution to D.08-09-038.

2. The claimed fees and costs, as adjusted herein, are comparable to market rates paid to experts and advocates having comparable training and experience and offering similar services.

3. The total of reasonable contribution is $96,715.

CONCLUSION OF LAW

1. The claim, with any adjustment set forth above, satisfies all requirements of Pub. Util. Code §§ 1801-1812.

ORDER

1. The Utility Reform Network is awarded $96,715.
2. Within 30 days of the effective date of this decision, Southern California Edison Company shall pay claimant the total award. Payment of the award shall include interest at the rate earned on prime, three-month commercial paper as reported in

Federal Reserve Statistical Release H.15, beginning February 7, 2009, the 75th day after the filing of claimant's request, and continuing until full payment is made.

3. The comment period for today's decision is waived.
4. Investigation 06-06-014 remains open to address other matters.

This order is effective today.

Dated March 12, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

APPENDIX A

Compensation Decision Summary Information

Compensation Decision:	D0903022	**Modifies Decision? No**
Contribution Decision(s):	D0809038	
Proceeding(s):	I0606014	
Author:	ALJ Barnett	
Payer(s):	Southern California Edison Company	

Intervenor Information

Intervenor	Claim Date	Amount Requested	Amount Awarded	Multiplier?	Reason Change/Disallowance
The Utility Reform Network	11-24-08	$107,491	$ 96,715	No	Excessive hours, miscalculations by TURN, duplication of efforts.

Advocate Information

First Name	Last Name	Type	Intervenor	Hourly Fee Requested	Year Hourly Fee Requested	Hourly Fee Adopted
Marcel	Hawiger	Attorney	The Utility Reform Network	$280	2006	$280
Marcel	Hawiger	Attorney	The Utility Reform Network	$300	2007	$300
Marcel	Hawiger	Attorney	The Utility Reform Network	$325	2008	$325
Robert	Finkelstein	Attorney	The Utility Reform Network	$405	2006	$405
Robert	Finkelstein	Attorney	The Utility Reform Network	$435	2007	$435
Gayatri	Schilberg	Expert	The Utility Reform Network	$175	2006	$175
Gayatri	Schilberg	Expert	The Utility Reform Network	$185	2007	$185
Greg	Ruszovan	Expert	The Utility Reform Network	$165	2006	$165

(END OF APPENDIX A)

Decision 09-07-019 July 9, 2009
DECISION ADOPTING GENERAL ORDER 133-C AND ADDRESSING OTHER TELECOMMUNICATIONS SERVICE QUALITY REPORTING REQUIREMENTS

COM/CRC/sid **Date of Issuance 7/16/2009**

Decision 09-07-019 July 9, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion into the Service Quality Standards for All Telecommunications Carriers and Revisions to General Order 133-B.	Rulemaking 02-12-004 (Filed December 5, 2002)

DECISION ADOPTING GENERAL ORDER 133-C AND ADDRESSING OTHER TELECOMMUNICATIONS SERVICE QUALITY REPORTING REQUIREMENTS

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DECISION ADOPTING GENERAL ORDER 133-C AND ADDRESSING OTHER TELECOMMUNICATIONS SERVICE QUALITY REPORTING REQUIREMENTS

1. Summary

The Commission opened this rulemaking to review and revise the existing service quality measures and standards (collectively, "measures")[1] under General Order (GO) 133-B applicable to telecommunications carriers.[2] Specifically, the Commission undertook to determine the kind of measures that should apply to local exchange and other services in light of changes in regulatory policies and increased market competition as found in this Commission's Uniform Regulatory Framework (URF) decision.[3] Consistent with the general agreement of the parties that competitive environments act to apply a natural pressure for carriers to ensure adequate service quality, it is reasonable to simplify the existing reporting requirements. At the same time, we do not believe a complete elimination of service quality reporting is warranted or

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[1] Measures are the aspects or features of service subject to evaluation and reporting. Standards are the minimum acceptable values that measures must meet to be in compliance with the Commission's requirements. Existing measures include held primary service orders, installation-line energizing commitments, trouble reports, dial tone speed, dial service, toll operator answering time, directory assistance operator answering time, trouble report service answering time, and business office answering time.

[2] By telecommunications carriers, this decision is referring to telephone corporations that are public utilities.

[3] URF carriers have full pricing flexibility over substantially all of their rates and charges. URF carriers include ILECs regulated through the Commission's uniform regulatory framework established in *Order Instituting Rulemaking on the Commission's Own Motion to Assess and Revise the Regulation of Telecommunications Utilities* ("*URF Phase 1 Decision*") [D.06-08-030] (2006) __ Cal. P.U.C.3d __, CLECs and interexchange carriers.

Footnote continued on next page

reasonable because this Commission has a statutory duty to ensure customers receive adequate service quality pursuant to Public Utilities Code §§ 709, 2896 and 2897. Accordingly, today's decision adopts GO 133-C[4] containing a minimum set of service quality measures. We believe continued reporting of these measures will ensure that telecommunications carriers provide relevant information to this Commission so that we may adequately protect California consumers and the public interest. The five service quality measures (and the related standards) we adopt are: (1) telephone service installation intervals (five business days); (2) installation commitments (95%); (3) customer trouble reports (six reports per 100 lines for reporting units with 3,000 or more working lines and lower standards for smaller units); (4) out of service (OOS) repair intervals (90% within 24 hours excluding Sundays and federal holidays, catastrophic events and widespread outages); and (5) answer time (80% within 60 seconds related to trouble reports and billing and non-billing issues with the option to speak to a live agent).[5] These five reporting measures will apply to General Rate Case (GRC) incumbent local exchange carriers (ILECs),[6] since they are fully

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[4] GO 133-C is attached as Attachment 1.

[5] Traffic offices with fewer than 10,000 lines shall be exempt from answer time reporting.

[6] An ILEC is a local telephone corporation that was the exclusive certificated local telephone service provider in a franchise territory established before the Telecommunications Reform Act of 1996 and is now regulated under URF, as established in Decision (D.) 06-08-030. (*See* Public Utilities (Pub. Util.) Code §§ 234 and 1001.) The Commission regulates GRC ILECs through cost-of-service reviews as required by GO 96-B. These carriers are designated carriers of last resort per *Re Universal Service and Compliance with the Mandates of Assembly Bill 3643* [D.96-10-066]

Footnote continued on next page

regulated as the monopoly provider in their service territories and are designated carriers of last resort (COLR) in their service territories.[7]

We will require reporting of fewer measures for Uniform Regulatory Framework (URF) ILECs[8] and competitive local exchange carriers (CLECs),[9] since these carriers operate in more competitive markets. The reporting measures we adopt for URF ILECs and for CLECs with 5,000 or more customers are: (1) customer trouble reports (six reports per 100 lines for reporting units with 3,000 or more working lines and lower standards for smaller reporting units); (2) OOS repair intervals (90% within 24 hours excluding Sundays and federal holidays, catastrophic events and widespread outages); and (3) billing, 6non-billing and trouble report answer time (80% within 60 seconds with the option to speak to a live agent).[10]

All measures except those related to answer time shall be reported quarterly. Answer time data shall be reported annually. Carriers' performance

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(1996) 68 Cal. P.U.C.2d 524, 625, which defined what is meant by basic telephone service for Universal Service funding.

[7] COLRs are required to serve upon request all customers within their designated service area. Pursuant to D.96-10-066, a carrier seeking to be a COLR needs to file a notice of intent with the Commission in order to have access to high cost fund subsidies. Once a carrier is designated as a COLR, it must obtain the Commission's approval to opt out of its obligation to serve.

[8] *See ante*, fn. 3.

[9] CLECs must obtain a CPCN to provide local telephone services in competition with ILECs in the service territories where ILECs formerly were the sole certificated provider. (*See* Pub. Util. Code §§ 234 and 1001 and *Re Competition for Local Exchange Service* [D.95-07-054] (1995) 60 Cal. P.U.C.2d 611.)

[10] Traffic offices with fewer than 10,000 lines shall be exempt from answer time reporting.

under the adopted measures shall be evaluated at least annually and may be published on the Commission's website to give consumers information about their carriers' service quality performance.

We grant an exemption from the requirement to report service quality measures under GO 133-C for certain carriers as described herein. Specifically, URF ILECs and CLECs with fewer than 5,000 customers are exempt unless the provider is a COLR.[11] Resellers, wireless and Internet protocol (IP)-enabled carriers (including Voice over Internet Protocol (VoIP) and cable) are also exempt.[12] We also narrow reporting for certain measures to residential and small business customers.

In addition, today's Decision formalizes major service interruption (MSI) reporting by adopting the Federal Communications Commission's (FCC) communication disruption and Network Outage Reporting System (NORS) reporting requirements and requiring a simultaneous written report to the Commission for communication disruptions and outages that affect California service. These requirements will apply to all facilities-based certificated and registered carriers. We discontinue reporting of the FCC's Merger Compliance Oversight Team (MCOT) data as outdated. However, we will continue to require carriers who file FCC Automated Reporting Management Information System (ARMIS) service quality and customer satisfaction data to file California-specific ARMIS data with this Commission as specified herein.

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[11] Currently, there are no URF ILECs with fewer than 5,000 customers.

[12] A wireless carrier (a Commercial Mobile Radio Service provider at the federal level) is a carrier or licensee whose wireless network is connected to the public switched telephone network. Wireless carriers are required to register with the Commission, and state level regulation is limited by federal law.

We require wireless carriers to provide coverage maps on their websites and at retail locations and to make these maps available during a sales transaction consistent with voluntary compliance agreements many wireless carriers have entered into with Attorneys General in other states. We discontinue the requirement that Pacific Bell Telephone Company d/b/a AT&T California (AT&T) submit OOS repair interval data pursuant to the standard we established in D.01-12-021. AT&T is instead directed to report the OOS repair interval data that is required under GO 133-C and ARMIS.

Finally, we defer a decision on whether to require an independent Commission customer satisfaction survey pending the outcome of a federal determination of what customer satisfaction data should be obtained for all service platforms.

2. Background

In 2002, the Commission issued an Order Instituting Rulemaking (OIR) to review, revise, supplement and expand, as necessary, elements of GO 133-B and to add new measures, procedures, standards and reports to the Commission's service quality rules.[13] The OIR recognized that technological and regulatory changes compelled the Commission to focus attention on the questions of what constitutes good service quality and how that should be measured, monitored and enforced.[14] One of the goals of increased competition was to ensure high quality service. A concern was expressed that competition might not be

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[13] Order Instituting Rulemaking on the Commission's Own Motion into the Service Quality Standards for All Telecommunications Carriers and Revisions to General Order 133-B, [R.02-12-004], mailed December 16, 2002.

[14] *Id.*, at p. 2.

sufficient in all markets to foster high service quality for all consumers.[15] Another issue raised in the OIR was whether minimal service quality rules continued to be necessary with competition and an intention to apply such rules across the board to all telecommunications providers was expressed.[16] The general issues to be considered were listed in Attachment 1 to the OIR and were very broad. The exact scope of the proceeding was to be determined in one or more scoping rulings issued by the assigned Commissioner.

In March 2003, the assigned Commissioner and Administrative Law Judge (ALJ) narrowed the issues for comment to: (1) adoption of measures for specific services proposed in Exhibit A to Attachment 1 of the OIR; (2) parties' cost/benefit analyses for adoption of those measures; (3) whether publishing carriers' reported data for service quality measures is a reasonable alternative or interim step to establishing standards and measure-specific quality assurance mechanisms for some measures; and (4) whether workshops centered on implementation issues would be productive after draft rules issue.[17] The Commission received extensive comments on the four issues identified in the ruling in April and May of 2003.[18]

In August 2006, a major decision in the URF proceeding, Rulemaking (R.) 05-04-005, undertook a long overdue review of the regulatory framework that the Commission applied to the four largest ILECs in the state, AT&T,

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[15] *Id.*

[16] *Id.* at pp. 9, 50-51.

[17] Assigned Commissioner and Administrative Law Judge's Ruling Denying In Part and Granting In Part Motion To Suspend, dated March 7, 2003.

[18] Parties commenting on these issues are listed in Attachment 2.

Verizon California Inc. (Verizon), SureWest Telephone (SureWest), and Citizens Telecommunications Company of California Inc., d/b/a Frontier Communications of California (Frontier). The primary goal of the URF proceeding was to develop a uniform regulatory framework that was technologically and competitively neutral, allowing the URF companies to better respond to competitive pressures they are facing from new competitors, such as cable voice providers, wireless carriers, and VoIP providers. The *URF Phase I Decision,* [D.06-08-030], *supra,* provided the large companies with regulatory treatment that was more symmetrical with that of the firms they compete with. URF granted substantial freedoms in the way that telephone companies price their non-basic residential services, offer services (*e.g.,* in bundles of services), and enter into contracts so they can compete on a level playing field. The Commission declined to allow pricing flexibility for residential basic local exchange services at that time, and put off pricing flexibility for basic service until January 1, 2009.[19] The *URF Phase I Decision*, as modified by D.06-12-044, deferred consideration of service quality issues, including service quality monitoring reports, to this proceeding.[20]

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19 *URF Phase 1 Decision, supra,* [D.06-08-030], at p. 154 (slip op.).

20 *Order Modifying and Granting Limited Rehearing of D.06-08-030 and Denying Rehearing in all Other Respects* [D.06-12-044] (2006)__ Cal.P.U.C.3d __, at p. 41 (slip op.) modifying D.06-08-030, at p. 78 [Conclusion of Law Number 52] (slip op.). Similarly, in connection with investigations regarding Cingular, Pacific Bell, and Verizon, the Commission concluded this proceeding was the proper forum to consider revisions to any service quality requirements. (*See In re Cingular* [D.04-09-062] (2004)__ Cal.P.U.C.3d __, at p. 5 (slip op.); and *In re Pacific Bell and Verizon California* [D.03-10-088] (2003) __ Cal.P.U.C.3d __, at p. 14 (slip op.). Finally, in connection with a complaint regarding AT&T's OOS repair interval penalty mechanism, the Commission again noted any revisions to company specific service quality measures were the subject of this proceeding. (*See The*

Footnote continued on next page

In March 2007, an Assigned Commissioner's Ruling and Scoping Memo updated the scope of the proceeding in light of the fact that the proceeding record was almost four years old, and the new assigned Commissioner sought a refreshed record which reflected the competitive and regulatory changes related to the *URF Phase I Decision* as well as the fact that competition among wireline, wireless and VoIP had been advancing in the California telecommunications market at a rapid pace during that era. [21] Additional comments were requested on: (1) whether the Commission should require and publish annual customer satisfaction surveys for telecommunications services; (2) whether the Commission should continue to monitor service quality under URF; (3) whether the Commission should monitor major service quality interruptions or California-specific downtime under ARMIS; and (4) whether the Commission should continue existing company-specific or California-specific measures and/or reports.[22]

In particular, the assigned Commissioner noted that the 2003 comments had lent support to adopting fewer service quality measures than proposed in the March 2003 ruling, to limiting service quality measures to basic local exchange access line service, and to publishing carriers' service quality data. However, because the comments were filed prior to the release of the *URF*

Office of Ratepayer Advocates v. Pacific Bell Telephone Company [D.07-04-019] (2007)__ Cal.P.U.C.3d __.)

[21] Assigned Commissioner's Ruling and Scoping Memo, dated March 30, 2007 (2007 ACR), including a revised Exhibit A with Sources. The proposed service quality measures contained in the OIR and revised Exhibit A are included in this decision as Attachment 3.

[22] 2007 ACR, at pp. 6-7.

Phase I Decision, new comments would be useful to consider a new approach and particularly, symmetric regulation among the classes of communications service providers regulated under URF and their competitors, which include CLECs, wireless service providers, and VoIP providers.[23]

Parties submitted opening and reply comments on May 14 and June 15, 2007, respectively.[24]

3. Issues Before the Commission

The following issues are now before the Commission for determination:

- Should the Commission require annual customer satisfaction surveys for all wireline and wireless services?[25]

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[23] *Id.* at pp. 3-4, noting D.06-08-030, *supra,* as modified by D.06-12-044, *supra,* at n. 3 (slip op.).

[24] Comments were filed by AT&T; Calaveras Telephone Company; Cal-Ore Telephone Co., Ducor Telephone Company, Global Valley Networks, Inc. (Global Valley Networks, Inc., has been merged into Citizens Telecommunications Company of California Inc. (D.08-02-014 and D.08-10-010) and is now an URF carrier), Foresthill Telephone Co., Happy Valley Telephone Company, Hornitos Telephone Company, Kerman Telephone Company; Pinnacles Telephone Co., The Ponderosa Telephone Co., Sierra Telephone Company, Inc., The Siskiyou Telephone Company, The Volcano Telephone Company, and Winterhaven Telephone Company (Small LECs); the California Association of Competitive Telecommunications Companies (CALTEL); Cbeyond Communications, LLC (Cbeyond); Frontier; CTIA-The Wireless Association (CTIA); Disability Rights Advocates (DisabRA); the Division of Ratepayer Advocates (DRA); Sprint Communications Company, L.P., Sprint Telephone PCS, L.P., Sprint Spectrum L.P. as agent for Wireless Co., L.P. d/b/a Sprint PCS, Nextel of California, Inc., Omnipoint Communications, Inc., d/b/a T-Mobile (T-Mobile), XO Communications Services, Inc., Astound Broadband, LLC, Time Warner Cable Information Services (California), LLC, and Time Warner Telecom of California, L.P. (Joint Parties); SureWest; The United States Department of Defense and All Other Federal Executive Agencies (DOD/FEA); The Utility Reform Network (TURN); Verizon California Inc. and its certificated California affiliates (Verizon); Verizon Wireless; and the VON Coalition (VON). DisabRA filed a motion to intervene on May 14, 2007 to permit it to file comments. No party objected to DisabRA's motion and it is granted.

wireless services since wireless capability is activated rather than installed, and wireless carriers do not dispatch technicians to repair wireless.[54]

Cbeyond argues that customer satisfaction surveys are not necessary for business customers, because there is sufficient competition in the business market and CLECs lack sufficient resources to conduct surveys and deploy new services and facilities.[55]

CTIA and Verizon Wireless echo the Joint Parties' position that customer satisfaction surveys are not meaningful for wireless carrier services, particularly given the range of existing surveys in the wireless industry.[56] CTIA also argues that Commission-sponsored surveys could distort the competitive market by giving the appearance that the Commission is endorsing the services of a specific carrier.[57] Finally, T-Mobile asserts that nothing suggests a Commission-sponsored survey would provide any additional material benefit to consumers.[58]

4.1.3. Discussion

We generally agree that Commission-required surveys could have the advantage of being a tool that applies to all aspects of intermodal voice competition. Unlike standards that cannot be applied to all types of carriers either due to differences in services (wireline versus wireless), or jurisdictional concerns (telephone corporations vs. wireless carriers vs. VoIP services), customer satisfaction surveys could reach both wireless and wireline customers

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54 *Id. at p. 6.*

55 Cbeyond 2007 Comments, at pp. 1-4.

56 CTIA 2007 Comments, at pp. 2-7; Verizon 2007 Comments, at pp. 3-4.

57 CTIA 2007 Comments, at p. 2.

58 T-Mobile 2007 Reply Comments, at p. 6.

served by any technology. We agree that customers and the market benefit from the availability of such information.

However, two factors lead us to conclude it is premature to adopt an independent Commission customer satisfaction survey as a component of service quality regulation under GO 133-C. One, the record reflects there are already many existing surveys which cover a range of issues and questions. An independent Commission survey would only be a valuable tool if it provides customers with new information that does not merely mirror other existing surveys. We do not believe the current record contains any specific proposal regarding what set of customer satisfaction attributes, and format, would be uniformly meaningful as an indicator of customer priorities across all carrier types (e.g., wireline, wireless, small carriers and large carriers).

Two, we believe we can benefit from information and evaluation that will come out of the FCC's pending rulemaking on customer satisfaction survey issues. The *FCC Service Quality Opinion* noted that service quality and customer satisfaction data could help consumers make informed choices in a competitive market but only if available from the entire relevant industry.[59] The Commission's goals are consistent with this viewpoint. To avoid redundancy, the results of the FCC's inquiry should be a starting point for any Commission adopted customer satisfaction survey. If the Commission ultimately undertakes to adopt its own service quality survey, the FCC's determination regarding what information and attributes most accurately reflect customer priorities across all service platforms would be an appropriate starting point.

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[59] *FCC Service Quality Opinion*, *supra* at ¶ 35.

Pending the FCC's decision on this issue, we require carriers that currently file ARMIS Report 43-06 with the FCC (AT&T and Verizon) to also furnish the California-specific data to this Commission's Director of the Communications Division at the same time. It is our understanding that customer satisfaction data will continue to be reported to the FCC at least until September 6, 2010.[60] If the FCC determines to continue Report 43-06 or modifies the required customer satisfaction data and/or the classes of carriers required to report, carriers should report California-specific data to this Commission accordingly. Should the FCC cease requiring customer satisfaction data, carriers should continue reporting California-specific Report 43-06 data to this Commission through December 31, 2011. If parties believe California-specific reporting should continue beyond that date, they should file a petition for rulemaking under Rule 6.3 of the Commission's Rules of Practice and Procedure with this Commission to seek consideration of whether an independent Commission survey should be required or some or all of California-specific ARMIS reporting should continue.

4.2. Service Quality Measures

As previously noted, the Commission's current service quality measures are embodied in GO 133-B. The GO requires all telephone utilities providing service in California to report on nine (9) measures.[61] Realizing that at least some of these traditional measures were becoming increasingly irrelevant and out of

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60 *Id.*

61 The service measures under GO 133-B are: held primary service orders; installation-line energizing commitments; customer trouble reports; dial tone speed; dial service; toll operator answering time; directory assistance operator answering time; trouble report service answering time; and business office answering time.

date due to changes in the competitive telecommunications market, the Commission opened this rulemaking to revise GO 133-B in a manner that would reflect current technological and business conditions. In particular, the 2007 ACR acknowledged that current service quality requirements are not technologically neutral and responsive to the competitive intermodal market.

In view of the fact that the existing service quality measures were adopted in the era of a monopoly landline phone system, all parties generally agree that some changes to the existing measures are warranted. The recommendations, in comments and reply comments filed in both 2003 and 2007, ranged from eliminating GO 133-B in its entirety, to revising it to reflect a smaller and more contemporary set of measures.[62] There was also general agreement that a one-size fits all approach does not make sense in view of the effect that different services, competitive conditions, and technologies may have on a consumer's view of service quality priorities.

It is undisputed that service quality measures and standards should apply to GRC ILECs and the GRC ILECs themselves recommend no changes to the current GO 133-B reporting requirements. URF ILECs and CLECs oppose being subject to service quality reporting. Consumer groups support revised standards for GRC ILECs, URF ILECs and CLECs.

TURN and DRA support revised service quality measures, as both legally required and necessary to monitor service quality for health and safety purposes. TURN and DRA propose measures for wireline carriers that largely are based on ARMIS reporting requirements per ARMIS Report 43-05 and not the current

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[62] Some parties' positions on the need for service quality measures changed from 2003 to 2007.

GO 133-B measures. They propose positive reporting of service quality measures at regular intervals rather than the current practice, exception reporting when carriers have not met existing standards. Other consumer groups and businesses also support streamlined measures.

Consistent with our stated statutory obligations, the record before us, and the intent of this OIR, we adopt GO 133-C, which revises and replaces GO 133-B's nine service quality measures with a minimum set of five service quality measures for carriers that provide local exchange service. These five measures are considerably narrowed from the 30 measures proposed in the OIR and reflect our acknowledgment of parties' comments and proposals for minimum service quality measures. The five measures will apply to GRC ILECs. In light of the competitive intermodal market, we will apply a somewhat reduced set of measures, three measures, to URF ILECs and CLECs that have more than 5,000 customers. These measures reflect our established policy of supporting reduced reporting requirements for competitive carriers.

In view of our current deference to the FCC's pending rulemaking regarding rules applicable to VoIP and IP-enabled services, we decline to impose service quality measures and standards on IP-enabled and VoIP providers (including cable). As discussed below, we also exempt resellers, wireless carriers, and small URF ILECs and CLECs with fewer than 5,000 customers.

Our goal is a uniform and consistent reporting format. A template for reporting the adopted service quality data is attached to the GO. Reporting of data for the new GO 133-C measures will begin on January 1, 2010.

4.2.1. Consumer Groups and Businesses Support Minimum Service Quality Measures

Both DRA and TURN propose a minimum set of service quality measures for wireline carriers.[63] The measures DRA proposes would apply to carriers with over 5,000 customers,[64] and would be reported on a positive basis each quarter. DRA's specific proposed measures are: operator service (reduces the GO 133-B answer time to one measure); time to reach a live operator (new);[65] trouble reports per 100 lines (existing GO 133-B);[66] installation commitments met (ARMIS);[67] installation intervals (ARMIS);[68] initial OOS repair intervals (ARMIS);[69] repeat out of service as a percentage of initial OOS reports (ARMIS).[70] DRA states reporting requirements should be limited to services provided to small business customers, those that purchase five or fewer lines.[71]

DRA asserts these minimum measures should be adopted as essential for consumer protection and public health and safety.[72] DRA contends the proposed

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63 In 2003, both AT&T and Verizon endorsed minimum standards comparable to the standards adopted in this decision. AT&T and Verizon no longer support minimum standards for URF carriers.

64 DRA 2007 Comments, at p. 21; DRA 2007 Reply Comments, at p. 11.

65 The standard would be 80% in 20 seconds.

66 The standard would be six per 100 lines with no differentiation between initial and repeat.

67 The proposed standard is 95%.

68 The proposed standard is five days for basic service orders only.

69 The proposed standard is 25 hours.

70 The proposed standard is 17%.

71 DRA 2007 Reply Comments, at p. 11.

72 DRA 2007 Comments, at pp. 2-3.

installation and repair measures are necessary to ensure California's telecommunications infrastructure is consistent with the national standards found in ARMIS.[73] DRA argues a sound infrastructure is necessary for California's economy, and California service providers should, at a minimum, perform as well as the telecommunications industry nationwide.[74] Further, DRA argues that repair standards are critical, because a customer who needs repair service does not have a competitive option. Nonetheless, DRA agrees measures should be streamlined from the 24 repair measures found in ARMIS.[75] DRA's proposed standards are based on a proxy for industry standards using historical data from 1996-2006. DRA averaged the performance of URF ILECs and GRC ILECs and the reference group of large ILECs the Commission used to compare the performance of AT&T and Verizon in D.03-10-088, *supra*. These averages were the basis of DRA's proposed standards for installation, maintenance and answer time.[76]

TURN proposes four indicators for wireline carriers:[77] average installation interval (per ARMIS standard);[78] average out of service repair interval (per ARMIS standard);[79] average wait time to speak with a live agent;[80] and

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[73] *Id.* at pp. 18-19.

[74] *See* D.03-10-088.

[75] DRA 2007 Comments, at p. 13.

[76] DRA Reply Comments, at p. 10.

[77] TURN 2007 Comments, at p. 11.

[78] The proposed standard is maximum three days for basic service orders only.

[79] The proposed standard is maximum 36 hours with no differentiation between initial or repeat.

Commission complaints per million customers.[81] In addition, TURN recommends the Commission monitor percent of calls receiving busy signal and percent of calls abandoned.[82] TURN recommends these measures be applied to all wireline carriers, including VoIP.[83]

In support of its proposed measures, TURN states that minimum service quality measures and information allowing comparisons between how various providers have fared in meeting such measures is a critical element in promoting consumer choice.[84] TURN notes that AT&T's own expert Harris stated in 2003 that minimum service quality measures ensure that customers will have a baseline level of quality, reducing the information needed to make buying decisions.[85]

A number of other parties also endorse minimum measures and point out that many states already have adopted minimum service quality measures applicable to incumbent and competitive carriers. For example, AARP noted that Ohio, Vermont, and Michigan have adopted minimum measures consistent

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80 The proposed standard is 60 seconds. The measure must be combined with the option on the company's answering menu to speak with a live agent after no more than 45 seconds of menu choices. TURN acknowledges that many issues can now be resolved by a customer's choice of menu options. However, more complex problems require a representative. (TURN 2007 Comments, at p. 9.)

81 TURN argues that while the level of actual complaints does not represent the true level of problems, this data presents real issues that customers face. (TURN 2007 Comments, at p. 10.)

82 TURN 2007 Comments, at p. 11.

83 TURN 2007 Comments, at pp. 7-11.

84 *Id.* at p. 5.

85 TURN Reply Comments at pp. 5-6, citing AT&T 2003 Comments, Appendix 3, at p. 20.

with the Commission's OIR proposal and that Washington, Oregon, Colorado, Illinois, Pennsylvania, Texas, and Florida have adopted generic service quality measures that focus on local exchange carriers.[86]

Allegiance provided more detail regarding those states' adopted minimum measures and also noted that Georgia and New York have adopted minimum measures.[87] Ohio's, Vermont's, Oregon's, Illinois' and New York's rules apply to ILECs and CLECs. Florida's and Georgia's rules exclude CLECs. The other states' rules apply to telecommunications carriers, generally.

DisabRA supports adoption of either the DRA or TURN proposals.[88] DOD/FEA recommends ARMIS reports be filed by carriers that currently provide that information to the FCC, that all ILECs continue to report under GO 133-B, and that CLECs report under GO 133-B or provide in the alternative, customer satisfaction and service quality data consistent with ARMIS Reports 43-05 and 43-06.[89]

NCLC supports minimum service quality measures covering installation, trouble reports, and answer time in order to assist consumers in obtaining the most valuable information.[90] The California Small Business Roundtable and California Small Business Association (CSBR/CSBA) stated that the issues most important to small business were how quickly carriers met service orders,

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86 AARP 2003 Comments, at p. 6.

87 Allegiance 2003 Reply Comments, at pp. 8-13.

88 DisabRA 2007 Reply Comments, at pp. 1-2.

89 DOD/FEA 2007 Comments, at pp. 12-13.

90 NCLC 2003 Comments, at p. 18.

responded to trouble reports, cleared outages and answered calls with a live person.[91]

4.2.2. Carriers' Positions on Service Quality Measures

AT&T and Verizon (i.e., the URF ILECs) oppose the DRA and TURN proposals, arguing that no evidence indicates the suggested measures are necessary for public health and safety, or are of particular concern to customers. For example, AT&T notes that 19 states do not regulate answer times. Further, AT&T argues there is no evidence or cost/benefit analysis to support the specific metrics TURN and DRA propose. AT&T estimates it would incur substantial costs to comply with the proposed answer time measure.[92]

AT&T and Verizon contend that all service quality measures and reporting requirements should be eliminated. They assert that in view of the development of competitive markets and the Commission's policy direction in URF, continued reporting to the Commission is unnecessary because competition is sufficient to protect consumers' interests.[93] Verizon adds that service quality measures are outdated, are not competitively and technologically neutral, and in its view distort the incentives competition already provides for achieving adequate service quality. Verizon suggests the Commission should rely on major service outage reporting and ARMIS data.[94]

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91 CSBR/CSBA 2003 Comments, at p. 3. In addition, CSBR/CSBA asserted small businesses value carriers' prompt correction of billing problems and keeping promises. *Id.*

92 AT&T 2007 Reply Comments, at pp. 13 n.60, 15, 16, 17.

93 Verizon 2007 Comments, at pp 1-3; AT&T 2007 Comments, at pp. 1-4.

94 Verizon 2007 Comments, at p. 2.

AT&T mirrors these arguments, commenting specifically that service quality measurements are outmoded, do not provide information for consumers to select among carriers, and impose costs on the affected carriers, which are not borne by other providers. AT&T notes that both GO 133-B and the FCC's MCOT reporting are outdated and are neither competitively nor technically neutral.[95] In AT&T's view, the Commission should rely solely on customer satisfaction surveys.[96]

SureWest argues that applying service quality obligations on regulated carriers distorts the competitive intermodal market. In SureWest's view, the costs of imposing reporting requirements outweigh the benefits.[97]

Frontier states GO 133-B requirements are duplicative, unnecessary and should be eliminated. Frontier would replace GO 133-B with federal and state MSI reports and third-party customer satisfaction surveys.[98]

The CLECs oppose continued GO 133-B reporting on the ground that their services are competitive and so obviate the need to continue GO 133-B reports.[99] They argue that the cost of compliance with GO 133-B or the DRA and TURN proposals would be prohibitive. CALTEL argues that CLECs predominantly serve medium to large business customers and must provide high quality service.[100] CALTEL argues that reporting requirements would increase

[95] AT&T 2007 Comments, at pp. 2, 11-15.

[96] AT&T 2007 Comments, at p. 2.

[97] SureWest 2007 Comments, at pp. 1-4.

[98] Frontier 2007 Comments, at pp. 1-6.

[99] Joint Parties 2007 Comments, at p. 9.

[100] CALTEL 2007 Reply Comments, at pp. 4-5.

operational costs for competitive carriers without justification, even with the small carrier exemption proposed by DRA.[101] Cbeyond elaborates on these concerns, stating that service quality measures are unnecessary for CLECs serving business customers because those customers have more competitive options, have access to greater resources, possess more technical expertise, and have greater bargaining power to resolve service quality disputes.[102]

VON argues that the Commission lacks jurisdiction over VoIP and should continue to defer to resolution of this issue in the pending FCC rulemaking to consider the regulatory treatment for VoIP and IP-enabled services.[103]

The Small LECs (i.e., GRC ILECs) are willing to continue reporting under the current GO 133-B.[104] They assert the data submitted in 2003 illustrated their excellent service to their customers and that nothing has changed since that time.[105] They argue that additional reporting would be expensive and unjustified, since GRC ILECs consistently have not had service quality problems, and continue to be subject to rate base regulation which affords the Commission opportunity to review their service.[106] Accordingly, the Small LECs oppose the DRA and TURN proposals and request an exemption from any new reporting requirements.[107] They assert DRA's rationale for exempting small carriers that

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[101] CALTEL 2007 Reply Comments, at pp. 5-6.

[102] Cbeyond 2007 Comments, at pp. 1-3.

[103] VON 2007 Reply Comments, at p. 4.

[104] Small LECs 2007 Comments, at pp. 1-3.

[105] *Id.*

[106] *Id.*

[107] *Id.* and Small LEC 2007 Reply Comments, at p. 3.

are not COLRs from new service quality standards applies to all small carriers. Cost and efficiency should influence the amount of service quality measurement and reporting required of smaller carriers.[108]

4.2.3. Discussion

As we have previously stated, the Commission has a statutory duty to ensure customers receive adequate service quality pursuant to Pub. Util. Code §§ 709, 2896 and 2897. We agree with the general consensus of the parties that certain aspects of GO 133-B are outdated and no longer reflect today's competitive markets and the Commission's regulatory policies consistent with URF. We also agree that ARMIS reporting could in some instances be a sufficient replacement for at least some aspects of our current reporting requirements. However, ARMIS data alone may not be enough, and the status of continued ARMIS reporting remains uncertain. If we were to rely solely on ARMIS data and the FCC were to eliminate ARMIS service quality reporting per ARMIS Report 43-05, it could compromise our ability to meet our statutory obligations to California customers.

We concur with DRA and TURN that minimum service quality measures and corresponding standards should be adopted to replace the existing GO 133-B measures. Although we do not adopt either proposal in its entirety, we will eliminate outdated components of GO 133-B, modify others, and rely on ARMIS measures and standards, where possible. We do not agree with the Small LECs' argument that GO 133-B measures should remain unchanged because the Commission has not found their particular service quality to be inadequate.

[108] *Id.* at pp. 3-4.

Adopting requirements based on the performance of any one group of carriers is not a practical or reasonable solution. As the parties have demonstrated, our existing service quality measures and standards lag behind current market realities as well as recently adopted minimum measures in force in other states. Our measures need to be revised. At the same time, we agree with the parties that while our requirements should strive to be competitively and technologically neutral, it is not practical to fashion identical service quality measures for all classes of carriers.

Today, we adopt GO 133-C to replace GO 133-B. GO 133-C does not contain outdated and inadequate service quality indicators that parties have recommended we eliminate. Measures that have been eliminated are: held primary service orders; installation-line energizing commitments; dial tone speed; and dial service. Answer time measures have been combined, and reporting for directory assistance and operator assistance answer times has been eliminated.

The revised minimum measures encompass metrics related to installation, repair, maintenance and answer time in fewer measures than found in GO 133-B. Based on the record before us, these are the indicators that are most relevant in today's more competitive telecommunications market to reflect actual customer priorities and satisfaction.

The minimum measures we adopt are: (1) telephone service installation intervals (five business days); (2) installation commitments (95%); (3) customer trouble reports (six reports per 100 lines for reporting units with 3,000 or more working lines and lower standards for smaller reporting units); (4) OOS repair intervals (90% within 24 hours excluding Sundays and federal holidays, catastrophic events and widespread outages); and (5) answer time (80% within

60 seconds related to trouble reports and billing and non-billing issues with the option to speak to a live agent).[109] These five reporting measures will apply to GRC ILECs, since they are fully regulated as the monopoly providers in their service territories and are designated COLRs in their service territories.

Fewer measures will apply to URF ILECs and CLECs since the competitive markets these entities operate in provide greater external pressure to ensure service quality and customer satisfaction. It is consistent with our policies in URF to minimize regulatory and reporting oversight in such competitive markets. The three measures we adopt for URF ILECs and CLECs are: (1) customer trouble reports (six reports per 100 lines for reporting units with 3,000 or more working lines and lower standards for smaller reporting units); (2) OOS repair intervals (90% within 24 hours excluding Sundays and federal holidays, catastrophic events and widespread outages); and (3) answer time (80% within 60 seconds related to trouble reports and billing and non-billing issues with the option to speak with a live agent).[110] Consistent with the recommendation of DRA, these measures will apply only to carriers with over 5,000 customers, unless the carrier is also a COLR.

We also narrow reporting for certain measures to residential and small business customers as explained below. We grant specific exemptions from GO 133-C reporting requirements as explained below.

We are aware that Pub. Util. Code § 321.1 states that it is the intent of the legislature for the Commission to generally assess the economic effects or

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[109] Answer time reporting shall be limited to traffic offices with 10,000 or more lines.

[110] Answer time reporting shall be limited to traffic offices with 10,000 or more lines.

consequences of its decisions. Consistent with that intent, the assigned Commissioner and ALJ requested comments in 2003 on the costs and benefits of the proposed measures. Few carriers provided specific or conclusive cost information either in 2003 or 2007 comments. We do not believe a lack of definitive cost information bars us from revising GO 133-B here.

As we have previously noted, § 321.1 does not require the Commission to perform a cost-benefit analysis or consider the economic effect of a decision on specific customer groups or competitors.[111]

Nor does it require the Commission to conduct analyses beyond those which can be accomplished with existing resources or structures. Lacking evidence to the contrary here, we believe it is reasonable to conclude that the overall reduction in reporting measures in the new GO 133-C should result in long-term cost savings for most carriers that currently report under the GO 133-B nine exception reporting categories, even though positive reporting is now required. Carriers should also realize some economic savings by our replacing the current Commission standard for MSI reporting with the FCC's NORS reporting, as discussed below.

4.2.3.1. Current Installation Standards

GO 133-B contains service quality measures for held primary service orders and installation-line energizing commitments. Held primary service orders measure installation delays over 30 days due to lack of plant. Installation-

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[111] *Order Instituting Rulemaking on the Commission's own Motion to Establish Consumer Protection Rules Applicable to All Telecommunications Utilities,* [D.06-12-042] [2006], pp. 17-18 __ Cal. P.U.C.3d __, (slip op.)

line energizing commitments measure the percentage of commitments met for non-key telephone service.

DRA states the held primary service order measure is not necessary since this is no longer a problem in California given the reduced demand for second lines.[112] TURN similarly contends the measure is no longer useful in that reporting trends suggest it may only reflect extremely poor installation performance rather than current customer expectations.[113] Cox adds that held service orders are inconceivable in competitive markets, since carriers have every incentive to provide service quickly.[114]

With respect to line energizing commitments, TURN states that the goal of meeting 95% of the commitments is too low to be meaningful, and carriers have exceeded the goal for many years. Thus, including this as a current measure would distort reporting results since it is so easily met.[115]

We agree that these measures are outdated and ineffective, and should be eliminated and replaced with more effective installation measures. The proposed measures which better indicate current service quality expectations are installation interval and installation commitments. These are discussed below.

4.2.3.2. Installation Interval

The standard we adopt for reporting installation intervals is based on ARMIS data, as recommended by both DRA and TURN. The installation interval measures the amount of time to install basic telephone service. If an

[112] DRA 2003 Comments, at p. 10.

[113] TURN 2003 Comments, at pp. 16-17.

[114] Cox 2003 Comments, at p. 15.

[115] TURN 2003 Comments, at pp. 16-17.

additional feature is included in a basic service installation, the installation interval should reflect the basic service installation. Measurement is done in business days and an average is calculated. Although TURN proposed three business days, we prefer the five business day standard proposed by DRA, consistent with the nationwide industry average.[116] This average is based on data compiled separately for small, mid-sized and large ILECs and is the lowest performance of a representative sample of carriers.[117] Small ILECs' average is consistent with the adopted standard, while mid-sized and large ILECs exceed the average. We believe TURN's proposed three business days is too far outside the industry average.

We next consider a proposed exemption from reporting for business customers. Cbeyond recommends such an exemption.[118] As previously noted, CBeyond maintains the level of competition in the market for business services is greater than residential, and business customers have greater resources and technical expertise, as well as bargaining power to resolve service quality concerns.[119] CALTEL asserts medium and large business customers are sophisticated customers that insist on a wide variety of voice and data solutions that deliver on both cost and quality. Most of these customers receive multiple bids from service providers and negotiate service guarantees and penalties as a part of individual-case-basis customers. Service quality for these carriers is good because it has to be. CALTEL has not been infirmed by Commission staff, either

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[116] DRA 2007 Reply Comments, at p. 10.

[117] *Id.*

[118] Cbeyond 2007 Comments, at pp. 1-2.

[119] *Id.*

the Consumer Affairs Branch or the Public Advisor's Office, of any documented or anecdotal evidence of systemic problems involving either individual carriers or the competitive industry as a whole.[120] DRA agrees somewhat, recommending that reporting for business customers be limited to small business customers, those that purchase five or fewer lines.[121]

DOD/FEA opposes an exemption, pointing to ARMIS data that illustrates California business customers are dissatisfied with maintenance and business office contacts comparable to dissatisfaction levels among residential customers.[122]

We recognize that competition is generally greater for business local exchange services than it is for residential services. The competitive landscape requires some accommodation for reporting on business services. Although we decline to exempt all reporting for business customers, we generally support DRA's proposal that it makes sense to limit reporting to smaller businesses. However, any exemption for reporting for larger business customers should have a definition that is consistent with what is reported under ARMIS. ARMIS makes no distinction between small and large business customers for reporting data per ARMIS Report 43-05. (*See* http://www.fcc.gov/wcb/armis/instructions/2008/definitions06.htm#T1C.)[123]

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[120] CALTEL 2007 Reply comments, at pp. 4-5.

[121] DRA 2007 Reply Comments, at p. 11.

[122] DOD/FEA 2007 Reply Comments, at p. 11. AT&T does not report disaggregated data for large business customers whereas Verizon does.

[123] However, ARMIS permits carriers to define small and large business customers for reporting customer satisfaction survey data per ARMIS Report 43-06. (http://www.fcc.gov/wcb/armis/instructions/2008/definitions05.htm#T2C.)

In addition, the current GO 133-B definition for small business is business accounts that are not designated by the utility for special handling. This definition is imprecise and subject to carrier interpretation. It does not meet our goal of a uniform and consistent reporting format. Instead, we find DRA's proposal to limit business services subject to reporting to small businesses purchasing five or fewer lines the most precise proposal. This proposal also is consistent with other states' definition of small business in terms of lines purchased.[124] We will limit installation interval reporting to services provided to residential and small business customers, consistent with DRA's proposal and requirements in other states.[125]

We will require data for this measure to be compiled monthly and reported quarterly. Quarterly reports will be due within 45 days of the end of the quarter. Carriers' performance shall be evaluated at least annually.

In adopting this measure, we recognize that the cost for carriers to change from the existing ARMIS requirement is not fully known.[126] In 2003, AT&T

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124 *See* New York Public Service Commission Notice of Issuance of Uniform Measurement Guidelines, p. 16, *http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/ArticlesByCategory/F1F99E0C9A229CC685256DF1004CC36D/$File/doc8602.pdf?OpenElement*. *See also* Michigan Telecommunications Service Quality Rules, R 484.520(1)(w) (small business defined as having three or fewer access lines), *In the Matter, on the Commission's own motion, to revise the service quality rules applicable to telecommunications providers*, 2007 Mich. PSC LEXIS 276, Exhibit A *51; Ohio Furnishing of Intrastate Telecommunications Service by Local Exchange Companies, OAC 4901:1-05-01 (FF) (small business defined as having three local exchange service access lines or less).

125 *See* Michigan R 484.558(1), *supra*; New York Public Service Commission Notice of Uniform Measurement Guidelines, *supra*, at p. 16.

126 Carriers that do not currently report this measure under ARMIS could incur additional costs to establish reporting.

estimated that its labor costs to report under a new requirement would be low.[127] Some parties have suggested that costs should not be limited to monetary costs, but that the Commission also should focus on the generalized economic costs of establishing uniform service standards.[128] Others argue there is no mandate to consider a cost-benefit analysis in the adoption of service quality measures, since Pub. Util. Code § 2896 requires the adoption of reasonable statewide service quality standards without a cost-benefit analysis.[129]

We also recognize it is difficult to compare tangible, out of pocket implementation costs with benefits that may not easily translate to dollar amounts. Service quality rules were not designed to provide direct financial benefits to consumers. Benefits are largely intangible, although poor customer satisfaction will certainly increase customer frustration and dissatisfaction. We note NCLC's suggestion that a regulated industry almost always over-estimates the costs of proposed regulations.[130]

In view of these considerations, and because the parties offered no evidence to find otherwise, we believe it would not be prohibitively costly to provide California-specific reporting of installation interval data. The URF ILECs already report under ARMIS. There is no disagreement that customer satisfaction with their carriers' service is likely to be higher with prompt basic

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[127] AT&T 2003 Comments, Attachment 2, at p. 10. AT&T's labor costs were filed under seal. Although AT&T's estimate does not necessarily have general applicability to other carriers, it is useful to assess a range of costs from low to high, even for measures that AT&T is exempt from reporting.

[128] Coalition 2003 Comments, at p. 29.

[129] NCLC 2003 Comments, at pp. 7-8.

[130] *Id.* at pp. 9-11.

service installation. Thus, it is probable the benefit of adopting this measure would exceed the cost.

This installation measure should apply to GRC ILECs, because they are the sole provider of basic local exchange service in their service territories. There is little or no competitive market. In contrast, minimum service quality measures for URF ILECs and CLECs should reflect the competitive landscape in which they operate. Competitive carriers have a strong incentive to install service promptly. That incentive is illustrated by the industry averages compiled by DRA. Mid-sized and large ILECs exceed the installation average of small ILECs. Thus, there is no need to require installation interval reporting for URF ILECs and CLECs. URF ILECs and CLECs are exempt from reporting installation intervals.

4.2.3.3. Installation Commitments

The standard we adopt for installation commitments is based on GO 133-B and ARMIS, as proposed by DRA. Installation commitments for basic service will be expressed as a percentage. The adopted standard is 95% of commitments met and excludes commitments that are not met due to customer actions. We believe DRA's proposal is reasonable since it is based on nationwide industry averages.[131] Small ILECs meet this average, while mid-sized and large ILECs exceed this average.[132] Consistent with DRA's proposal, this measure is limited to installation intervals for residential and small business customers. We will require installation commitments met to be compiled monthly and reported

131 DRA 2007 Reply Comments, at p. 10.

132 *Id.*

quarterly. Quarterly reports will be due within 45 days of the end of the quarter. Carriers' performance shall be evaluated at least annually.

There is no evidence establishing the cost for carriers to change from the existing reporting measure to this new measure. In 2003, AT&T estimated that labor costs to report under a new requirement would be low.[133] Consistent with our reasoning above, customer satisfaction with their carriers' service will likely to be higher if installation commitments are met and thus, it is probable the benefit of adopting this measure would exceed the cost.

This reporting measure will apply to GRC ILECs because they are the sole provider of basic local exchange service in their service territories. Thus, this standard is adopted for GRC ILECs. Minimum service quality measures for URF ILECs and CLECs should reflect the competitive landscape in which they operate. Competitive carriers have a strong incentive to meet installation commitments and install service promptly. That incentive is illustrated by the industry averages compiled by DRA. Mid-sized and large ILECs exceed the installation average of small ILECs. Thus, there is no need for installation commitment standards for URF ILECs and CLECs. URF ILECs and CLECs are exempt from reporting installation commitments.

4.2.3.4. Customer Trouble Reports

The existing GO 133-B customer trouble report standard measures initial trouble in relation to lines or equipment. It is expressed as the number of reports per 100 lines. DRA supports retaining the existing standard, which is six reports per 100 working lines for reporting units with 3,000 or more lines, eight reports

[133] AT&T 2003 Comments, Attachment 2, at p. 7.

per 100 working lines for reporting units with 1,001-2,999 working lines, and 10 reports per 100 working lines for reporting units with 1,000 or fewer working lines.[134] The smaller the GRC ILEC, the more lenient the standard.[135] A significant benefit to retaining this measure is its illustration of network reliability.[136]

TURN recommends we eliminate this particular measure, reasoning that the threshold of six trouble reports per 100 lines (and up to ten trouble reports for smaller central offices) is far too high to represent good service and that carriers significantly exceed this standard.[137] TURN prefers we require reporting of the number of complaints per million customers. TURN argues that complaint data represents the real issues that customers face.[138]

We decline to adopt a standard associated with the number of complaints received by the Commission. Although complaints are one indicator of customer dissatisfaction, they normally span a range of issues which may or may not be tied to the actual indicators of service quality adopted under GO 133-C. We believe that on whole, customer trouble reports will provide more useful and relevant information. Although TURN argues that six reports per 100 lines is a weak standard, no other party supports that position. The Small LECs support continuation of the existing standard.[139] Accordingly, we will retain the

[134] DRA 2007 Comments, p. 9.

[135] DRA 2007 Reply Comments, at pp. 9-10.

[136] DRA 2007 Comments, at p. 9.

[137] TURN 2003 Comments, at p. 17.

[138] TURN 2007 Comments, at p. 10.

[139] Small LECs Comments, at p. 3.

minimum standard of no more than six trouble reports per 100 working lines with more lenient standards for smaller central office sizes: eight reports per 100 working lines for units with 1,001-2,999 working lines and ten reports for units with 1,000 or fewer lines. This standard for customer trouble reports is based on GO 133-B and ARMIS. This measure will apply to local exchange service provided to residential and business customers, consistent with ARMIS and requirements in other states.[140] Customer trouble reports will be compiled monthly and reported quarterly. Quarterly reports are due within 45 days of the end of the quarter. Carriers' performance shall be evaluated at least annually.

We next address the DRA and TURN recommendation that trouble reports must be defined consistently. We agree. DRA recommends that all calls to the repair center should count as true troubles, without exclusion.[141] We believe that may be too broad. For purposes of reporting this measure, customer trouble reports are defined as all reports affecting service as well as those regarding service that is not working.

As with the preceding measures, there was no evidence quantifying the precise costs for carriers to comply with this measure. In 2003, AT&T estimated that labor costs to report under a new requirement would be low.[142] In as much as we are largely retaining the existing standard, we do not expect the cost to be burdensome. Customer satisfaction with their carriers' service is likely to be higher if service is reliable, and the incidence of trouble reports is one measure of

140 *See* DRA 2007 Comments, p. 14; New York Public Service Commission Notice of Issuance of Uniform Measurement Guidelines, *supra*, at pp. 4-5.

141 DRA 2003 Comments, at p. 15.

142 AT&T 2003 Comments, Attachment 2, at p. 21.

reliability. Thus, it is probable the benefit of adopting this measure would exceed the cost. This service quality measure shall apply to GRC ILECs, because they are the sole provider of basic local exchange service in their service territories. We believe URF ILECs and CLECs should also be responsive to customers and prompt in addressing service difficulties. In this respect, the reporting of maintenance standards represented by the incidence of customer trouble reports would be beneficial. Maintenance standards such as this address critical health and safety concerns, and the industry averages compiled by DRA illustrate that larger ILECs tend to have lower performance on maintenance standards than do smaller ILECs. Further, not all customers in service territories of URF ILECs have competitive choices. Thus, we will require URF ILECs and CLECs to report this measure. However, consistent with DRA's overall recommendation, we will only require this reporting for URF ILECs and CLECs with 5,000 or more customers, unless the carrier is a COLR.

4.2.3.5. Out of Service Repair Intervals

GO 133-B does not currently require the reporting of OOS repair intervals. This indicator reflects how long a customer may have to wait to have service repaired. Both TURN and DRA recommend we adopt such a service quality measure. TURN suggests we use the ARMIS definition and set a maximum goal of 36 hours.[143] DRA recommends 25 hours.[144]

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143 TURN 2007 Comments, at p. 9 (also referencing ARMIS 43-05, rows 144, 145, 148, and 149).

144 DRA 2007 Reply Comments, at p. 10.

Decision 09-03-025 March 12, 2009
ALTERNATE DECISION OF PRESIDENT PEEVEY ON TEST YEAR 2009 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

Decision 09-03-025 March 12, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA EDISON COMPANY (U338E) for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2009, And to Reflect That Increase In Rates.	Application 07-11-011 (Filed November 19, 2007)
And Related Matter.	Investigation 08-01-026

(See Appendix A for a list of appearances.)

ALTERNATE DECISION OF PRESIDENT PEEVEY ON TEST YEAR 2009 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

ALTERNATE DECISION OF PRESIDENT PEEVEY ON TEST YEAR 2009 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

1. Summary

This decision authorizes a $4.829 billion base revenue requirement for test year 2009 for Southern California Edison Company (SCE or Edison). We find that the authorized revenue requirement provides SCE with sufficient funding to provide safe and reliable service at just and reasonable rates. The adopted revenue requirement represents a 28.8% increase over the 2006 authorized revenue requirement of $3.749 billion, a 19.3% increase over SCE's 2006 recorded base revenue requirement of $4.106 billion, an 11.35% increase over the projected revenue requirement at present rate levels of $4.334 billion, and a 7.78% reduction from the 2009 revenue requirement requested by SCE of $5.205 billion,[1] which represented a 20.1% increase over the projected revenues at present rates. The adopted methodology for calculating post-test year revenue requirement results in a revenue requirement for 2010 of $5.035 billion and for 2011 of $5.254 billion. This decision also authorizes a 41.85% increase in SCE's total company rate base. In 2006, the authorized rate base was $10.4 billion. Today, we increase the authorized rate base to $14.77 billion. As a result of our decision today, SCE's projected total company revenue requirement for 2009 is approximately $12.5 billion. This proceeding is closed.

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[1] When SCE filed its request for a TY 2009 revenue requirement with the Commission on November 19, 2007, it requested a revenue requirement of $5.199 billion. In May 2008, SCE reduced parts of its request by approximately $13 million to reflect the economic downturn. Exhibit SCE-24A, p. 37. Later, in SCE's update testimony filed on September 4, 2008, SCE presented an updated revenue requirement of $5.205 billion.

Decision 13-08-022 August 15, 2013

DECISION GRANTING COMPENSATION TO THE UTILITY REFORM NETWORK FOR SUBSTANTIAL CONTRIBUTION TO DECISION 12-11-051

Decision 13-08-022 August 15, 2013

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to, Among Other Things, Increase Its Authorized Revenues for Electric Service in 2012, And to Reflect that Increase in Rates.	Application 10-11-015 (Filed November 23, 2010)

DECISION GRANTING COMPENSATION TO THE UTILITY REFORM NETWORK FOR SUBSTANTIAL CONTRIBUTION TO DECISION 12-11-051

Claimant: The Utility Reform Network (TURN)	**For contribution to Decision (D.) 12-11-051**
Claimed ($): $1,131,257.37	**Awarded ($): $1,097,201.90** (reduced 3.0%)
Assigned Commissioner: Michael R. Peevey	**Assigned ALJ: Melanie M. Darling**

PART I: PROCEDURAL ISSUES

A. Brief Description of Decision:	D.12-11-051 resolves Southern California Edison Company's (SCE) test year 2012 general rate case. The decision adopted a 2012 revenue requirement representing the reasonable costs of providing safe and reliable electrical service to SCE's customers in that year. The Commission reduced SCE's request for 2012 operations and maintenance (O&M) expenses by $258 million, and reduced the request for 2010-2012 capital spending by $756 million. The decision also adopts post-test year increases for 2013 and 2014.

B. Claimant must satisfy intervenor compensation requirements set forth in Public Utilities Code §§ 1801-1812:

	Claimant	**CPUC Verified**
Timely filing of notice of intent to claim compensation (NOI) (§ 1804(a)):		
1. Date of Prehearing Conference:	January 31, 2011	Correct
2. Other Specified Date for NOI:	N/A	N/A
3. Date NOI Filed:	March 2, 2011	Correct
4. Was the NOI timely filed?		Yes
Showing of customer or customer-related status (§ 1802(b)):		
5. Based on ALJ ruling issued in proceeding number:	See Comment #1	See Comment(s)
6. Date of ALJ ruling:	See Comment #1	See Comment(s)

7. Based on another CPUC determination (specify):	See Comment #1	N/A
8. Has the Claimant demonstrated customer or customer-related status?		Yes
Showing of "significant financial hardship" (§ 1802(g)):		
9. Based on ALJ ruling issued in proceeding number:	Petition 10-08-016	Correct
10. Date of ALJ ruling:	November 22, 2010	Correct
11. Based on another CPUC determination (specify):		
12. Has the Claimant demonstrated significant financial hardship?		Yes
Timely request for compensation (§ 1804(c)):		
13. Identify Final Decision:	D.12-11-051	Correct
14. Date of Issuance of Final Order or Decision:	December 10, 2012	Correct
15. File date of compensation request:	January 25, 2013	Correct
16. Was the request for compensation timely?		Yes

C. Additional Comments on Part:

#	Claimant	CPUC	Comment
1	X		TURN understands that the ALJ Division has adopted a practice of only issuing a formal ruling on an intervenor's notice of intent if the intervenor is seeking to demonstrate significant financial hardship, rather than relying on the rebuttable presumption created by an earlier finding of hardship. TURN's showing on financial hardship (relying on the rebuttable presumption) and customer status was contained in our NOI. TURN has previously been found to satisfy these two standards -- for example see ALJ ruling on January 3, 2012 in Rulemaking 11-11-008.
2		X	The Commission has reviewed TURN's revised bylaws submitted to the Commission on October 28, 1996. Section III states that TURN is organized to "train consumer law advocates…engaged in scientific research on the operations of administrative agencies…publish research…represent the interest of consumers in administrative and judicial decision making process(es) regarding public utility matters…" The Commission upholds past proceedings finding TURN eligible under Pub. Util. Code § 1802(b). We remind TURN that it must provide a copy of its bylaws or articles of incorporation, or cite to a formal proceeding in which these documents have been previously submitted. Since TURN has provided the Commission with a copy of this information, no further copies are required, unless TURN amends such bylaws or articles of incorporation in the future. Thus, TURN is eligible to seek intervenor compensation in this proceeding having the requisite showing of customer or customer-related status.

PART II: SUBSTANTIAL CONTRIBUTION

A. **Claimant's claimed contribution to the final decision** (see § 1802(i), § 1803(a) & D.98-04-059):

Contribution	Specific References to Claimant's Presentations and to Decision	Showing Accepted by CPUC
<u>Overview</u>: This General Rate Case (GRC) proceeding covered an array of issues associated with SCE's electric generation and distribution utility functions. TURN submitted testimony from six witnesses on a wide variety of those issues, and addressed additional issues through our cross-examination of SCE witnesses during the evidentiary hearings. As TURN will describe in more detail below, TURN's efforts resulted in a substantial contribution on the vast majority of issues addressed in our testimony and briefs. In D.12-11-051, the adopted outcomes on the issues TURN addressed were generally consistent with TURN's recommendation. Even where the Commission did not adopt TURN's recommended outcome even in part, it often cited with favor TURN's analysis of the issue. Therefore the Commission should have no trouble determining that TURN's substantial contribution on the wide array of issues addressed in this GRC warrants the requested award of compensation. TURN relies largely on our opening brief as the source for citations to where the arguments and evidence supporting our substantial contributions appear in the record of this proceeding. The cited pages from that brief should point the Commission toward the prepared and oral testimony and other record evidence supporting TURN's position. Should the Commission conclude that it needs further support for any of the substantial contributions described here, TURN requests an opportunity to supplement this showing with additional citations as appropriate.		Yes
1. Overall outcome – The Commission calculated a $5.671 billion revenue requirement authorized for 2012, as compared to the updated 2012 revenue requirement of $6.294 billion requested by SCE. TURN can take credit for a substantial portion of this reduction of $623 million for 2012.	D.12-11-051, at 3.	Yes
2. Policy – TURN recommended that the Commission find SCE's "headcount" results from its Results of Operation (RO) model to be unreliable because they bear no relationship to SCE's actual personnel and employment decisions.	TURN Opening Brief, at 5-13.	Yes

The Commission addressed the use of the RO model for this purpose, calling it "not a reliable indicator of eventual results."	D.12-11-051, at 22-23.	
3. Generation – Solar Photovoltaic Program (SPVP) TURN recommended that the capital expenditure forecast be trued up to actuals for 2010 because the lower figure was more consistent with the reality that the utility would not complete the forecast work for 2012. TURN further recommended that the O&M expense forecast be reduced due to the fact that fewer projects would operate in 2012, and (along with DRA) opposed SCE's proposal to eliminate the SPVP balancing account because of the risk that the forecasted spending would be far greater than the actual spending. After the GRC was submitted, the Commission issued D.12-02-035 modifying the SPVP and reduced the forecasted projects and the associated cost forecasts by 50%. In recognition of this post-briefing change, the Commission adopted an O&M forecast of 50% of the amount SCE had requested, an outcome that subsumed TURN's recommendations. While the Commission did not embrace TURN's recommended capital spending adjustments based on a "true-up," it adopted a reduced spending level for 2011 through 2014 to be consistent with D.12-02-035. Finally, the Commission rejected SCE's proposal to eliminate the SPVP balancing account.	TURN Opening Brief, at 29-33. D.12-11-051, at 82-83.	Yes
4. Generation – Catalina Diesel TURN's recommendations focused on four issues: SCE's requested write-off of $1.3 million it had spent on an undersea cable project (and a further reduction of $20 million in rate base for what TURN believes to be SCE's imprudent management of the project); removal of $11.9 million for the forecasted capital costs of the switchrack project proposed for late 2014; reduction of Catalina-related O&M costs that SCE conceded should be removed from the forecast; and removal of $5.2 million as the capital forecast for a "betterment" project. The Commission adopted outcomes consistent with a substantial portion of TURN's recommendations. While it rejected the proposals related to the undersea cable project, it declined to consider the proposed 2014 spending on the switchrack project, and agreed with TURN that the entire amount forecast for 2011-2012 for the station betterment should be excluded.	TURN Opening Brief, at 46-51 and 315-316. D.12-11-051, at 86-92.	See Section D. "CPUC Disallowances & Adjustments"

TURN's substantial contribution on these issues is also evident in the SCE agreement to remove $200,000 from its O&M forecast.		
5. Generation – Fuel Cells TURN's testimony called for a reduction of the 2010 capital forecast for fuel cells based on the fact that the expected spending for that year was far closer to zero than to the forecast of $6.3 million. SCE's rebuttal testimony objected to this reduction; shortly thereafter, the utility committed to reduce its rate base request during the update phase of the proceeding. The decision notes that SCE's update testimony reduced the original forecast by 44%, from $19.1 million to $10.6 million to reflect the reduced program scope.	TURN Opening Brief, at 51-52. D.12-11-051, at 92-93.	Yes
6. TDBU – Advanced Technology O&M For advanced technology activities, SCE requested $23.8 million in O&M expenses for 2012, and $170 million of capital spending for 2010-2012, with $72 million in 2012 alone. The Commission adopted forecasts of $18.7 million for 2012 O&M, and 2011-2012 capital expenditures of $120.6 million. TURN recommended no GRC funding of Home Area Network (HAN) technologies to the extent that the related SmartConnect activities are within the deployment plan scope and period. The Commission agreed, and removed 2012 HAN-related costs from the GRC for recording and later review in the SmartConnect Balancing Account. TURN raised a number of challenges to SCE's proposed funding for PEV Readiness. The Commission found merit in TURN's arguments, but sought to provide some funding since SCE was undertaking these activities as a mandated initiative. It adopted a forecast of $3.6 million for 2012, approximately $900,000 below the amount SCE requested.	D.12-11-051, at 103. TURN Opening Brief, at 64-66. D.12-11-051, at 105-106. TURN Opening Brief, at 54-63. D.12-11-051, at 109-111.	Yes
7. TDBU – Advanced Technology Capital TURN presented a broad challenge to SCE's proposed Advanced Technology capital expenditures due to the utility's failure to present a cost-effectiveness analysis for those projects. The Commission reiterated its recognition that cost-benefit analysis is appropriate, as explained in D.10-06-047. TURN recommended removal of $10.7 million proposed	TURN Opening Brief, at 68-71. D.12-11-051, at 113-114.	Yes

for the "Self-Healing Circuit" pilot project, pending completion of the Irvine demonstration project and a preliminary cost-benefit analysis. The Commission agreed. TURN recommended ceasing funding of the Online Transformer Monitoring project in 2011, due to SCE's study indicating that the benefits could be achieved more cost-effectively. The Commission permitted ongoing funding for the project, but at a level $2.9 million below the approximately $10 million the utility sought for 2011 and 2012. SCE requested $6.8 million for 2010 and $16.5 million for 2011 for the Centralized Remedial Action Scheme (C-RAS) project, but reported recorded spending of $0.364 million in 2010. TURN recommended no funding in either 2010 or 2011 due to mistaken assumptions about the CAISO interconnection queue and the absence of any showing of operational benefits outweighing the costs. The Commission substantially reduced the forecast for 2010 and 2011 to $6.7 million total, citing in part the questions about the necessity for the proposal in light of revised interconnection estimates.	TURN Opening Brief, at 81-85. D.12-11-051, at 118-119. TURN Opening Brief, at 87-96. D.12-11-051, at 121-123. TURN Opening Brief, at 96-99. D.12-11-051, at 124-127.	
8. TDBU – T&D Load Growth TURN challenged the spending forecast for the Presidential Substation in SCE's Distribution Substation Plan, on the basis that SCE's reduced forecast of load growth and admission that it did not expect to construct the substation in 2012 warranted its removal from the test year forecast. The Commission agreed and removed the $23.0 million forecast for 2011 and 2012 for this project. TURN challenged capital funding for "PEV readiness" at this time, in part due to the utility's overly optimistic forecast of PEV roll-out. The Commission generally agreed with TURN and DRA that the program's estimate was based on an "excessive forecast" and adopted a 2011-2012 forecast of $6.4 million, approximately $4.2 million below the amount the utility had requested.	TURN Opening Brief, at 101-104. D.12-11-051, at 142-143. TURN Opening Brief, at 56-59. D.12-11-051, at 144-146.	Yes
9. TDBU – T&D Customer Driven Programs TURN presented alternative forecasts for meter sets to better reflect the lower growth due to the lingering economic effects of the recession. The Commission adopted TURN's base case forecast as the most reasonable estimate of growth in SCE's service territory, resulting in a 27-30% reduction in the residential meter set forecast for 2011-2012, and a 19-26% reduction in	TURN Opening Brief, at 104-110. D.12-11-051, at 171-176.	Yes

non-residential meter sets for that period. These changes resulted in a $60 million reduction in forecasted capital expenditures related to new meter sets and service connections in 2011 and 2012.		
10. TDBU – Overhead Line Operations TURN provided additional support for DRA's reduced forecast based on the last recorded year, rather than SCE's methodology. The Commission found DRA's and TURN's approach more reasonable, and therefore adopted a $593,000 disallowance as compared to SCE's requested amount.	TURN Opening Brief, at 113-114. D.12-11-051, at 211-213.	Yes
11. TDBU – Distribution Construction and Maintenance (DCM) TURN recommended meter-related expenses of $5.8 million, a reduction of approximately $600,000 as compared to SCE's litigation position (which the utility had reduced by $290,000 to reflect agreement with one of TURN's proposed adjustments). The Commission adopted TURN's recommendation. For overhead breakdown expense, TURN recommended a $1.2 million reduction from SCE's requested amount. The Commission adopted TURN's recommendation. Similarly, for the underground breakdown expense, the Commission adopted TURN's recommendation of approximately $1 million below the amount SCE requested. For distribution storm and claims damages capital expenditures, SCE agreed to reductions of $700,000 and $5 million, respectively, to correct TURN-identified calculation errors. TURN. The Commission adopted the resulting forecast as reasonable. For breakdown maintenance capital expenditures, the Commission reduced the forecast for 2011-2012 by $5.7 million, based in part on TURN-raised questions about SCE's forecast methodology. The Commission adopted TURN's forecast of distribution transformer capital expenditures, since the forecast is consistent with TURN's forecast of customer growth, which the Commission also adopted. The result is a $9.5 million reduction to SCE's 2011-2012 forecast.	TURN Opening Brief, at 121-123; 118-119; 119-121; 123-124; and 128-131. D.12-11-051, at 226-227; 233-235; 235-237; 237-238; 238-240; and 241.	Yes

12. TDBU – Other Costs and Other Operating Revenue TURN recommended reducing the forecast for transmission work order write-offs to $0.74 million, based on an adjusted five-year average. The Commission used different adjustments to a five-year average and adopted a forecast of $1.2 million, approximately $1.5 million below SCE's request. Similarly, TURN recommended reducing distribution work order write-offs to $8 million. The Commission used different adjustments to a five-year average and adopted a forecast of $8.2 million, approximately $1.8 million below SCE's request. For claims write-offs, TURN recommended $5.4 million, again based on an adjusted five-year average. And again, the Commission used different adjustments to adopt a forecast of $5.7 million, a $300,000 reduction to SCE's request.	TURN Opening Brief, at 132-153. D.12-11-051, at 289-296.	Yes
13. CSBU – Plug-in Electric Vehicle Costs For Plug-in Electric Vehicle (PEV) costs, TURN recommended zero funding, consistent with the position taken in the TDBU-related discussion of the issue. The Commission adopted a 40% reduction to SCE's forecasts to reflect the lower adopted growth forecast. For CSBU-related HAN costs, TURN recommended that any authorized spending should be treated as deployment costs that should be recovered through the ESCBA, subject to the cost cap in that account. The Commission agreed.	TURN Opening Brief, at 208-209. D.12-11-051, at 312-317.	Yes
14. CSBU – Customer Service Operations Division TURN's general recommendations to remove PEV readiness costs and to assign HAN functionality costs recorded in the ESCBA were applied to SCE's forecast for the Customer Service Operations Division to remove the HAN functionality costs, and reduce the PEV forecast by 40%, thus reducing the GRC-adopted amounts by approximately $750,000.	D.12-11-051, at 323-325.	Yes
15. CSBU – Customer Service and Information Delivery For account management expenses, TURN recommended that costs associated with responding to customer inquiries regarding Dynamic Pricing should be removed from the GRC forecast and recorded in the ESCBA, and PEV-related funding should be removed altogether. The Commission agreed regarding the DP-related costs	TURN Opening Brief, at 169-170. D.12-11-051, at 345-347; and 349-352.	Yes

through 2012 ($440,000), and reduced the PEV-related forecast by approximately $120,000. For program management expenses, TURN recommended PEV- and DP-related reductions, and challenged the increase for EnergyManager costs. The Commission again directed the 2012 DP-related costs be recorded in the ESCBA, reduced PEV-related costs by 40% (a reduction of approximately $1 million in 2012), but agreed with SCE on the EnergyManager funding.		
16. CSBU – Metering Capital Requirements TURN's general recommendations to remove PEV readiness costs and to assign HAN functionality costs recorded in the ESCBA were applied to capital expenditure forecasts for meters, as well as the reduction to rely on a forecast of lower customer growth. The Commission agreed that SCE's forecasts are excessive, and reduced the 2010-2012 capital expenditures by approximately $22 million.	D.12-11-051, at 364-365.	Yes
17. CSBU – Capitalized Software TURN recommended that the Commission disallow funding for upgrades to SCE's interactive voice response (IVR) system, due to a failure to demonstrate that the project is necessary at this time. The Commission agreed, resulting in a reduction of approximately $8.2 million for 2010-2012 capital expenditures. For SCE's customer relationship management (CRM) project, TURN recommended eliminating funding altogether due to the lack of any quantifiable benefit. The Commission approved the forecast for the first phase of funding, but with a 10% ($4.5 million) reduction for 2010-2011 spending. TURN recommended removing all funding for SCE's HAN support and troubleshooting project due to a lack of need, and in the alternative recommended that the project's costs be recorded in the ESCBA. The Commission denied funding based on its finding that implementation is premature.	TURN Opening Brief, at 177; 205-206; and 213-215. D.12-11-051, at 368-373.	Yes
18. Information Technology (IT) – ERP Benefits and Benefits from Capitalized Software TURN recommended that the Commission reject SCE's proposals to share the 2012 ERP benefits and operational savings from capitalized software 50/50 between ratepayers and shareholders. The Commission declined to adopt SCE's proposals.	TURN Opening Brief, at 178-180. D.12-11-051, at 385-388.	Yes

19. IT – O&M for New Software Applications TURN recommended a $24.13 million reduction to SCE's $40.681 million estimate to remove SmartConnect project costs to the ESCBA, and to reduce the forecast commensurate with the proposed reduction to the IT new project request and for recurring O&M expenses. SCE conceded a reduction of $2.8 million for 2012 SmartConnect costs. The Commission adopted a forecast of $26.4 million, approximately $13.5 million below SCE's adjusted request.	TURN Opening Brief, at 196-197. D.12-11-051, at 390-392.	Yes
20. IT – Capital Expenditures – Operating Software TURN challenged the $3.75 million of expenditures SCE proposed for the Configuration Management Database software package due in part to the lack of cost justification. The Commission agreed and removed the associated costs from the adopted forecast. TURN recommended disallowance of $500,000 for the Single View of IT Health project because the cost estimate had subsequently increased substantially and the project duplicates an existing inventory of software applications. The Commission agreed and removed the associated costs from the adopted forecast.	TURN Opening Brief, at 200-202. D.12-11-051, at 409-411.	Yes
21. IT – Capitalized Software – Software Asset Management TURN recommended a 10% reduction to all authorized expenditures due to SCE's failure to prioritize projects. The Commission found such a reduction reasonable for all 2011 and 2012 requested expenditures by 10% or approximately $9.8 million. TURN recommended a number of further reductions to specific projects in this category, including a proposal to reduce funding for the replacement of SCE's Energy Manager by $4.4 million. The Commission reduced funding by 50% ($3 million).	TURN Opening Brief, at 180-238. D.12-11-051, at 413; 420-422; and 425.	Yes
IT – ERP Project Cost Overruns SCE recorded cost overruns of $94.7 million for implementation of ERP in 2009 and 2010. TURN recommended disallowance of this amount due to imprudence and SCE's faulty cost-effectiveness analysis. The Commission agreed with TURN, but limited the disallowance to the 2010 capital expenditures of $49.6 million.	TURN Opening Brief, at 197-200. D.12-11-051, at 426-428.	Yes

22. IT -- Review in the Next GRC Relying heavily on the critique presented by TURN and the concerns raised therein regarding the quality of SCE's showing in support of its hundreds of millions of dollars of spending, the Commission called for a more detailed review of SCE's capitalized software requests in the next GRC.	D.12-11-051, at 435-436.	Yes
23. Human Resources (HR) – Executive Officer Compensation, Stock Options and Long-Term Incentives TURN recommended limiting rate recovery to 50% of the forecast for the Executive Incentive Compensation plan, a $3.2 million reduction from SCE's forecast. The Commission adopted TURN's recommendation. TURN recommended eliminating rate recovery of the costs of the Long Term Incentive program for executives, a $19.8 million reduction. The Commission adopted this forecast.	TURN Opening Brief, at 241-256. D.12-11-051, at 448-452.	Yes
24. HR – Pensions and Benefits For the 401(k) Savings Plan, TURN recommended a $4.5 million reduction using a five-year average of contributions, but SCE's labor escalation rate. The Commission adopted this forecast. For Medical Programs, TURN recommended a $22 million reduction based in part on a 4.4% escalation rate rather than the 10% proposed by SCE. The Commission adopted TURN's recommendation. For Disability Programs, TURN recommended a $1.7 million reduction based on per-employee costs. The Commission adopted TURN's recommendation.	TURN Opening Brief, at 258-268. D.12-11-051, at 467-473.	See Section D. "CPUC Disallowances & Adjustments"
25. A&G – Workers' Compensation TURN proposed an incremental reduction of $347,000 to the staff costs. The Commission found TURN's forecast to be more reasonable based on annual claims data and actual industry caseload standards.	TURN Opening Brief, at 271-277. D.12-11-051, at 499-500.	Yes
26. A&G – Corporate Membership Dues and Fees: SCE reduced its forecast for this department by approximately $400,000 in response to TURN's objections and evidence. TURN recommended further reductions based in part on the lobbying nature of some of the activities funded through these dues and fees. The Commission adopted TURN's forecast of approximately $300,000 below SCE's adjusted request.	TURN Opening Brief, at 283-286. D.12-11-051, at 506- 507.	Yes

27. A&G – Corporate Communications TURN recommended $12.1 million as the forecast for labor and expenses for corporate communications. The Commission adopted a $12.4 million forecast, relying heavily on TURN's proposed adjustments to reduce the forecast by $2.3 million as compared to SCE's request. TURN recommended $544,000 for outside services based on the last recorded year of data. The Commission adopted this forecast, a reduction of $360,000 as compared to SCE's request. TURN recommended $980,000 for communications products based on the last recorded year of data with an adjustment for additional customer safety education. The Commission adopted this forecast, a reduction of $165,000 as compared to SCE's request.	TURN Opening Brief, at 287-292. D.12-11-051 at 508-511.	Yes
28. Power Procurement Capital Expenditures: The Commission cited TURN's general concern about SCE's forecast costs for capitalized software projects, and applied a 10% reduction to many of the projects SCE proposed for 2010-2012. The $5.3 million cumulative disallowance for these capital projects includes approximately $2.0 million from these 10% reductions.	D.12-11-051, at 539-540; and 543-544.	Yes
29. Operations Support Business Unit (OSBU): Transportation Services Division TURN recommended elimination of funding for SCE's proposed OnBoard Technology project, and reduction of SCE's forecast for vehicle license fees. TURN accepted SCE's revised request for $600,000 for the vehicle license fees (a $600,000 reduction). The Commission did not approve the $1.4 million for O&M or the $10.6 million of capital expenditures associated with the OnBoard Technology project.	TURN Opening Brief, at 295-298. D.12-11-051, at 562-564 and 589-590.	Yes
30. OSBU – Capital Expenditures TURN recommended that the Commission eliminate SCE's proposed 10% contingency factor, and reduced the project management costs sought by the utility. The Commission removed the 2012 contingency factor of $7.884 million, and reduced the project management costs by 50% of the difference between SCE's and TURN's positions, or $1.872 million. TURN sought a reduction of $5.1 million to SCE's forecasted furniture expenditures for 2012. The Commission adopted a forecast that split the difference between TURN's recommendation and SCE's figure, a $2.284 million reduction.	TURN Opening Brief, at 308-310 and 312-314. D.12-11-051, at 568-571.	Yes

31. OSBU – Corporate Resources Capital Projects TURN recommended disallowance of the 2010 and 2011 capital expenditures on the Rosemead Data Center life extension project. The Commission disallowed the 2011 request of $4.5 million. TURN challenged the $12 million forecast for the Gateway Parking Structure as excessive, and recommended $7.1 million. The Commission adopted TURN's forecast.	TURN Opening Brief, at 305-308. D.12-11-051, at 577-578; and 580.	See Section D. "CPUC Disallowances & Adjustments"
32. OSBU – Energy Efficiency TURN recommended reducing SCE's forecast of $5 million per year to $1 million per year, in part due to the absence of cost-benefit information necessary to ensure the spending achieves appropriate cost savings. The Commission adopted a forecast of $3 million per year, and directed SCE to provide a cost-benefit analysis of all such energy efficiency projects implemented since 2009 and to allocate quantified cost savings to ratepayers.	TURN Opening Brief, at 298-301. D.12-11-051, at 583-584.	Yes
33. Ratemaking – Shareholder Sharing of Pension and Benefit Costs SCE sought to remove pensions and benefits associated with below-the-line FERC accounts. TURN recommended that an additional $754,000 should be removed. SCE agreed to this adjustment, as indicated in the decision.	TURN Opening Brief, at 319-320. D.12-11-051, at 595.	Yes
34. Taxes – Employee Stock Ownership Plan (ESOP) TURN recommended termination of the ESOP Tax Memorandum Account (ESOPTMA). The Commission terminated the account.	TURN Opening Brief, at 329-333. D.12-11-051, at 622-623.	Yes
35. Rate Base – Customer Deposits TURN defended the existing policy that requires SCE to offset rate base by some amount of customer deposits. The Commission declined to alter its policy, and offset 90% of the forecast of customer deposits ($190 million) against rate base.	TURN Opening Brief, at 329-333. D.12-11-051, at 627-630.	Yes
36. Rate Base – Working Cash TURN recommended a $20 million reduction to the working cash rate base to reflect a more recent Gas Options Premium forecast. The Commission stated its agreement with TURN's concern that changes to utility hedging policy would impact SCE's hedging and related prepayment forecasts. It therefore based the working cash for gas option prepayments on a 15% increase over	TURN Opening Brief, at 339-343. D.12-11-051, at 637-638 and 643-645.	Yes

2009 recorded amounts, rather than 33%. TURN's inquiries about lag days associated with employee benefits and unfunded executive retirement benefits led SCE to revise its estimate from zero to 3.06 days, resulting in a rate base reduction of $692,000. TURN also recommended lag days for payroll to the calculation of 401(k) benefit plan lag days. The Commission agreed and adopted TURN's recommendation to apply SCE's labor lag days to 401(k) expense.		
37. Rate Base – Legacy Meters and Mohave TURN recommended that the net plant balance associated with electromechanical meters that had been replaced with automated meter infrastructure (AMI) meters should be removed from rate base, with the remaining investment amortized over a six-year period, but with no authorized return on the unamortized investment. The Commission adopted a six-year amortization period for the retired legacy meters, at a reduced authorized return of 6.46%. TURN also recommended amortization of SCE's remaining $54 million of investment and $36 million of estimated decommissioning costs in the Mohave Generating Station, but with no authorized return. The Commission adopted TURN's recommendation, although with a slightly shorter amortization period (6 years rather than 6.5 years).	TURN Opening Brief, at 351-360. D.12-11-051, at 649-653.	Yes
38. Non-Tariffed Products and Services (NTP&S) TURN raised a number of concerns regarding the gross revenue sharing mechanism (GRSM) applicable to SCE's NTP&S, and recommended either modification or elimination of the GRSM, adjustment of the threshold revenues before sharing is triggered, and an audit of NTP&S activities. The Commission did not adopt any changes to the GRSM, but called for the next affiliate transaction audit to include a focused review of the NTP&S program, including SCE's development of incremental costs.	TURN Opening Brief, at 360-376. D.12-11-051, at 656-658.	Yes
39. Depreciation TURN recommended different mass property lives than SCE proposed for ten of the largest accounts (as measured by plant investment). The Commission agreed with TURN that SCE's use of "judgment" to select curve-lives is often opaque, and the explanations for changes tended to be limited and conclusory. The Commission relied on TURN's recommended values in	TURN Opening Brief, at 376-408. D.12-11-051, at 662-669; 675-681; and 684-686.	Yes

part or in whole for Accounts 354, 355, 364, 365, and 367. TURN also recommended different mass property net salvage values for ten of the largest accounts. The Commission cited with favor a number of the concerns raised in TURN's analysis, and for seven of the accounts adopted net salvage rates that were more positive than proposed by SCE, with the rate for three of these accounts based on TURN's proposal or a modified version of the proposal. TURN recommended reporting requirements with regard to providing aged life analysis data, net salvage rate differences between SCE and other industry members, and a retirement cause analysis. The Commission agreed that aged data is more likely to be reliable than the simulated life data used in the SCE study, and directed SCE to address use of aged data in its next GRC. It further directed SCE to provide testimony in its next GRC providing more information about cost of removal where its proposed net salvage rate is at least 25% more than comparable industry average.		
40. Reliability Investment Incentive Mechanism (RIIM) The Commission adopted the RIIM settlement between CCUE and SCE over TURN's objections. However, it also found that the persistent uncertainty about the effects of the program should be addressed. To that end it ordered an independent audit of the 2010-2011 RIIM expenditures and a comparison of short term reliability statistics to total RIIM expenditures since 2003.	TURN Opening Brief, at 157-167. D.12-11-051, at 698-701.	Yes

B. Duplication of Effort (§§ 1801.3(f) & 1802.5):

	Claimant	CPUC Verified
a. Was the Division of Ratepayer Advocates (DRA) a party to the proceeding?	**Y**	**Verified**
b. Were there other parties to the proceeding with positions similar to yours?	**Y**	**Verified**
c. If so, provide name of other parties: Aglet Consumer Alliance, Joint Parties (representing Black Economic Council, National Asian American Coalition, and Hispanic Business Chamber of Commerce of Los Angeles), Eastern Sierra Ratepayer Association, Disability Rights Advocates, and Sierra Club.		**Verified**

d. Describe how you coordinated with DRA and other parties to avoid duplication or how your participation supplemented, complemented, or contributed to that of another party: TURN's work in a GRC is typically very closely and efficiently coordinated with other like-minded groups, and this case was no different. In light of the scope of the proceeding and the magnitude of the requested rate increase, TURN worked especially hard to achieve such coordination and, as a result, maximum coverage for ratepayers. Our time records include a number of entries (usually coded as "coord" or "GP") for efforts that were primarily devoted to communicating with the other intervenors about matters such as procedural strategies and issue area allocation. As is our regular practice in such proceedings, TURN closely coordinated with Aglet Consumer Alliance (Aglet) and DRA from the earliest stages of the GRC. With Aglet, such coordination enabled TURN to identify the issues Aglet was likely to address and thus limit duplication. With DRA, avoiding duplication is nearly impossible (since the staff seeks to address nearly all issue areas covered by the utility application). Therefore the coordination effort with DRA aims to minimize duplication and to ensure that where such duplication occurs TURN's witnesses are presenting distinct and unique arguments in support of the common or overlapping recommendations. As a result, the Commission ended up with a more robust record upon which to evaluate the issue at hand. In most instances, however, TURN raised unique issues, thus broadening the overall presentation of DRA and other intervenors and avoiding duplication altogether. TURN also closely coordinated our efforts with those of Aglet and DRA during the period in which those parties discussed with SCE potential settlement of their issues in the proceeding. Aglet took the lead in those discussions on behalf of TURN, thus permitting TURN to keep to a relative minimum the time devoted to the discussion and analysis of potential settlement outcomes. In sum, the Commission should find that TURN's participation was efficiently coordinated with the participation of other intervenors wherever possible, so as to avoid undue duplication and to ensure that any such duplication served to supplement, complement, or contribute to the showing of the other intervenor.	**Verified**

PART III: REASONABLENESS OF REQUESTED COMPENSATION

A. General Claim of Reasonableness (§§ 1801 & 1806):

a. Concise explanation as to how the cost of Claimant's participation bears a reasonable relationship with benefits realized through participation:	**CPUC Verified**
TURN's request for intervenor compensation seeks an award in excess of $1 million as the reasonable cost of our participation in the proceeding, making it one of the largest that TURN has presented to the Commission. In light of the scope and quality of TURN's work, and the benefits achieved through TURN's participation in the proceeding, the Commission should have little trouble concluding that the amount requested is reasonable. As the decision notes, SCE's application included thousands of pages of	Verified

testimony and workpapers, sponsored by 88 witnesses. (D.12-11-051, at 6.) The resulting decision calculates a $5.671 billion revenue requirement authorized for 2012, as compared to the updated 2012 revenue requirement of $6.294 billion requested by SCE. (*Id.*, at 3.) As described above in the substantial contribution section, TURN can take credit for a substantial portion of this reduction of $623 million for 2012. Furthermore, a substantial portion of the savings achieved in the test year will persist throughout the attrition years as well. The Commission could find the amount of TURN's requested award reasonable even if it limited its review to compare the amount requested with the revenue requirement reductions achieved by those TURN recommendations to which SCE agreed. The Joint Comparison Exhibit, Vol. 1, at 46 calculates $5.1 million as the 2012 reduction from such recommendations, covering a wide array of utility operations. If these were the only TURN recommendations reflected in the final outcome, they would still represent a benefit/cost ratio of at least 4:1 in the test year alone, and likely over 10:1 if the persistence over the rate case cycle is considered. The requested compensation amount is a very small fraction of the savings directly attributable to TURN's work on disputed issues in the proceeding. For example, TURN's depreciation testimony recommended life-curves and net salvage ratios for the FERC accounts with the largest plant balances. The final decision cited with favor TURN's analysis, and for a number of these accounts adopted TURN's recommended outcome or an outcome between TURN's and SCE's recommendations. TURN's rough estimate of the impact of the Commission-adopted outcomes for the depreciation expense associated with these accounts is a reduction in excess of approximately $100 million.[1] TURN's contribution on the depreciation-related issues alone represent a benefit/cost ratio approaching 100:1 in the 2012 test year alone, and 300:1 if the impact over the three-year GRC cycle is considered. Of course, TURN's work in this proceeding covered much more than the issues on which SCE agreed and depreciation parameters. As the substantial contribution discussion above makes very clear, TURN's efforts helped achieve a wide array of outcomes where the Commission agreed in whole or in part with TURN's recommendation, most of which resulted in reductions to the authorized revenue requirement. In sum, the Commission should conclude that TURN's overall request is reasonable in light of the substantial benefits to SCE ratepayers that were directly attributable to TURN's participation in the case.	

[1] (This is a conservative estimate, in that it is based on 2009 plant balances <u>and</u> does not reflect the final revisions to the Proposed Decision that included rejecting SCE's proposed 30-year life for the 40-year life TURN had proposed for plant in Account 367, the largest mass property account.)

b. Reasonableness of Hours Claimed TURN's attorneys and consultants recorded a substantial number of hours for their work on this GRC. However, this is true of any GRC, as TURN tends to address a very broad array of issues (typically second only to DRA in terms of breadth of coverage) and devotes substantial time to review of the utility's showing, preparation of discovery, and development of the testimony positions and arguments. As described below and as further reflected in the time records attached to this request, the number of hours for each TURN representative was reasonable under the circumstances present here. In past compensation awards the Commission has criticized time records for failure to meet the requirements of Rule 17.4, in particular the directive that the time records identify "the specific task performed" and "the issue that the task addresses." (*See, for example,* D.12-03-024 (Award in PG&E 2011 GRC Application (A.) 09-12-020), at 23.) TURN respectfully submits that this criticism has often been misplaced, as the time records in question are often from the early stages of a proceeding when an intervenor's work is largely devoted to an initial broad review for issue spotting purposes. Thus there are a number of entries in the time records for late 2010 and early 2011 that merely refer to a "review" of certain materials. If TURN's consultant was performing an initial review of a particular volume of SCE IT testimony and supporting workpapers on a given day, there is not much more detail to report other than "review IT testimony." Similarly, TURN's consultants often use the volume number of the testimony as a shorthand reference to the subject area. The parties involved in the GRC understand that any testimony labeled SCE-2 is going to be generation-related, and SCE-3 is TDBU-related. Therefore, while the Commission has faulted TURN for a failure to include in the time record a description of what document was involved in that day's work, the criticism seems to be based in part on a lack of familiarity with the numbering protocol for SCE testimony in the GRC. If it would assist with the Commission's review of these records, TURN would be glad to provide a key that lists the various SCE testimony volumes by number and topic for cross-referencing purposes. <u>TURN Attorneys:</u> Marcel Hawiger served as the lead and coordinating attorney, as well as covering several issue categories for purposes of testimony review, hearing room work (cross-examination and defending TURN's witness), and briefing. TURN seeks compensation for approximately 320 of his hours here, or the equivalent of approximately 8 weeks of full-time work. Robert Finkelstein played a wide-ranging and labor-intensive role throughout this proceeding. TURN seeks compensation for approximately 650 of his hours here, or the equivalent of approximately 15-20 weeks of full-time work. Mr. Finkelstein recorded substantial numbers of hours for TURN's work on policy issues (in large part because he attended the opening hearings in Los Angeles on behalf of TURN and therefore was responsible for preparing for and cross-examining several of SCE's policy witnesses). He also served as TURN's attorney and witness on the topics of NTP&S and the reduced rate of return for replaced meters and the Mohave power plant. Mr. Finkelstein also devoted substantial time to	See Section D. "CPUC Disallowances & Adjustments"

depreciation-related issues. (TURN has omitted from this request the approximately 50 hours Mr. Finkelstein recorded for work on matters related to the McGrath Peaker in this GRC.) Four other TURN staff attorneys worked on this PG&E GRC. Nina Suetake and Hayley Goodson each assumed responsibility for discrete issue areas (including TDBU and tax issues for Ms. Goodson, IT and CSBU issues for Ms. Suetake). TURN seeks compensation for approximately 250 hours for each, or the equivalent of approximately 6-8 weeks of full-time work. In addition, Marybelle Ang bore lead responsibility for the meter set forecast that was a critical element of TURN's substantial contribution in a number of TDBU areas, as well as discrete A&G issues. TURN seeks compensation for approximately 120 hours for her work, or the equivalent of 3 weeks of full-time work. [**a number of generation-related issues, as well as TURN's analysis of the rate impacts of PG&E's proposed revenue requirement increase. TURN seeks compensation for approximately 650 of his hours here, or the equivalent of approximately 15-20 weeks of full-time work.**] Finally, Tom Long recorded a small number of hours in his role as TURN's litigation director, consulting regarding strategy on several discrete issues. TURN submits that the recorded hours are reasonable, both as described above and as demonstrated in the wide-ranging substantial contribution TURN made in this proceeding. Therefore, TURN seeks compensation for all of the hours recorded by our attorneys and included in this request. <u>JBS Energy</u>: JBS Energy once again played an instrumental role in TURN's participation in this GRC by covering a broad array of issues, and conducting an in-depth review of past spending patterns and forecasts for this GRC. As has been our practice in GRCs in recent years, TURN's consultant's review of the SCE showing in this GRC began earlier in the process, shortly after the utility served its "Notice of Intent" in late summer 2010. This more extensive general review early in the process was a lynchpin of TURN's generally successful efforts in this GRC, both in terms of developing a general strategy and for focusing TURN's work on particular issue areas. And the substantial number of hours this request for compensation includes for the associated work of JBS Energy were a critical part of this approach and, ultimately, of TURN's success. In light of the breadth of TURN's substantial contribution and the dollar impact of many of the issues on which we prevailed (either in whole or in part), the increased amount of intervenor compensation is a very cost-effective investment for SCE's ratepayers. Seven members of JBS Energy's staff worked on the SCE GRC, with four of them sponsoring testimony on behalf of TURN. William Marcus's testimony covered policy issues and an array of different O&M and capital issues, including generation, meter sets forecast, executive compensation, A&G expenses, and working cash. Gayatri Schilberg's testimony focused primarily on information technology issues, as well as a few discrete electric distribution issues. Jeff Nahigian's testimony covered corporate real estate (in the Operations Support Business Unit) and SmartConnect costs and benefits (in the Customer Services	Language in brackets under "TURN Attorneys:" apparently was not intended to be in the text."

Business Unit). And Garrick Jones both performed much of the analysis supporting Mr. Marcus's testimony and sponsored testimony on pensions and benefits (in Human Resources) and advanced technology projects (in the Transmission and Distribution Business Unit). In addition, Greg Ruszovan of the firm, whose specialties include data compilation and analysis, provided critical assistance in support of Ms. Schilberg's IT analysis and testimony. John Sugar, who had recently joined the firm, performed much of the analysis supporting Mr. Marcus's testimony on executive compensation. Finally, Jim Helmich recorded a very small number of hours performing analysis regarding Catalina generation that fed into Mr. Marcus's testimony on SCE's spending in that area.

Diversified Utility Consultants, Inc.:
Jack Pous, President of DUCI, bore primary responsibility for the development and presentation of TURN's depreciation testimony in this proceeding, and assisted with preparation of the briefs on those issues. At times Mr. Pous was able to delegate work to Sara Coleman, a senior associate at DUCI, and Erin Ladd, an associate at the firm, thus reducing the total cost of service to TURN.

Woodruff Expert Services:
This request includes approximately 10 hours for Kevin Woodruff. One of the issues that came up in the area of working cash and rate base was the appropriate treatment of prepayments of gas options that Edison claimed had grown substantially in recent years in order to meet the utility's hedging requirements established in the long-term procurement plan (LTPP) proceeding. Mr. Woodruff is the expert witness TURN relies on in most LTPP matters, and is more familiar with the gas options and hedging requirements in that proceeding than is Mr. Marcus. Therefore Mr. Woodruff played an important consulting role to Mr. Marcus for the TURN testimony on this issue and, analyzing SCE's rebuttal testimony and assisting in the development of cross-examination and other hearing strategies for this issue.

Meetings or discussions involving more than one TURN attorney or expert witness:
A relatively small percentage of hours and hourly entries reflect internal and external meetings involving two or more of TURN's attorneys and expert witnesses. In past compensation decisions the Commission has deemed such entries as reflecting internal duplication that is not eligible for an award of intervenor compensation. This is not the case here. For the meetings that were among TURN's attorneys and expert witnesses, such meetings are essential to the effective development and implementation of TURN's strategy for this proceeding. None of the attendees are there in a duplicative role – each is an active participant, bringing his or her particular knowledge and expertise to bear on the discussions. As a result, TURN is able to identify issues and angles that would almost certainly never come to mind but for the "group-think" achievable in such settings.

There were also meetings with other parties at which more than one attorney represented TURN on occasion. The Commission should understand that this is often essential in a case such as this one, with a wide range of issues that no single person is likely to master. TURN's requested hours do not include any for a

TURN attorney or expert witness where his or her presence at a meeting was not necessary in order to achieve the meeting's purpose. TURN submits that such meetings can be part of an intervenor's effective advocacy before the Commission, and that intervenor compensation can and should be awarded for the time of all participants in such meetings where, as here, each participant needed to be in the meeting to advance the intervenor's advocacy efforts. Travel: There is a small amount of travel time and expenses associated with TURN's attorney attending the first two days of evidentiary hearings that were conducted in Los Angeles. Since three SCE policy witnesses testified on areas addressed in TURN's testimony during those hearings, TURN's presence was essential to our effective participation in the proceeding. Compensation Request Preparation Time: TURN is requesting compensation for 30.0 hours devoted to compensation-related matters, primarily preparation of this request for compensation (28.75 hours). While higher than the number of hours TURN tends to seek for compensation-related matters, this is a reasonable figure in light of the size and complexity of the request for compensation itself. The number of hours devoted to a request for compensation is driven in large part by the number of individuals and daily time entries involved in the substantive work. For example, the greater the number of individuals, the greater the likelihood that the request will need to address a new hourly rate for some of those individuals. In D.09-10-051, the Commission awarded compensation for the full 30.0 hours requested for compensation-related work in the SCE 2009 GRC. However, in the PG&E 2011 GRC the Commission reduced the requested 24.25 hours by 15%, in part due to perceived deficiencies in TURN's claim, and in part due to a determination that the "claim was not complex from the legal standpoint and the formal record in support of the claim was not voluminous." D.12-03-024, at 25-26. TURN has striven to fully address issues that have in the past caused the Commission to find deficiencies in our requests for compensation. Given the nearly 900-page final decision, with more than 1000 separately stated findings of fact and over 550 conclusions of law, and TURN's 400-page opening brief based on testimony of six witnesses and extensive references to the hearing testimony of many more witnesses, TURN is confident the Commission will not reach the same conclusion about the formal record for this claim. Mr. Finkelstein prepared this request for compensation because his extensive knowledge of many aspects of this proceeding, combined with his experience with GRCs in general, would enable him to prepare the request in a more efficient manner than if it were prepared by one of the other attorneys. Furthermore, each of TURN's attorneys devoted time to reviewing hourly records and identifying and explaining substantial contributions; TURN has excluded the bulk of those hours from this request. In sum, the Commission should find that the number of hours claimed is fully reasonable in light of the complexity of the issues and TURN's relative success on the merits.	

c. Allocation of Hours by Issue TURN has allocated all of our attorney and consultant time by issue area or activity, as evident on our attached timesheets. The following codes relate to specific substantive issue and activity areas addressed by TURN. Code — Stands for: GP — General Participation – work that would not vary with the number of issues that TURN addresses, for the most part GH — General Hearing – Hearing-related (preparation and participation), but not issue-specific. Due to the nature of GRC hearings and witness scheduling, TURN attorneys spent time in the hearing room waiting for the witness they would cross-examine to take the stand. To the extent possible, TURN's attorneys used the time in the hearing room to perform other substantive work (such as preparing for the NEXT witness in queue), with the time recorded to the related substantive issue. Comp Ex — Comparison Exhibit – Preparation of TURN positions for Comparison Exhibit PD — PD/AD – work on analyzing, commenting on, lobbying on, strategizing on the PD/AD/revisions thereto Proc — Procedural – Procedural motions (such as TURN's motion for a memorandum account, TURN's response to an SCE motion to strike), scheduling matters, etc. Coord — Coordination with other parties -- meetings and e-mails w/ DRA, other intervenors about issue coverage, etc. Settle — Time devoted to settlement discussions and development of settlement-related materials -- analysis of offers, negotiation, strategizing, etc. Policy — Substantive work on policy issues TDBU — Transmission and Distribution Business Unit – primarily Electric Distribution O&M and Capital NTP&S — Non-Tariffed Products and Services A&G — Administrative and General Gen — Fossil Decommissioning, Fossil O&M, Hydro Capital, Nuclear O&M IT — Information Technology – IT hardware and software in various business units, including IT&BI, CSBU, PPBU, A&G and HR. RB — Rate base – customer deposits, working cash	Verified

Dep	Depreciation – TURN's expert witness and his support team further allocated to general depreciation (GD), average service lives (ASL), net salvage (NS), and reimbursed retirements (ReimbRet). Some of their time entries had more than one allocation code, with a percentage indicated. Rather than re-enter the data in separate lines, TURN assigned an allocation code based on which code reflected the work that had the higher percentage for that date. Where the percentage indicated a 50/50 split, TURN used an alternating allocation.	
Tax	Payroll, income, and other tax issues	
CSBU	Customer Service Business Unit – O&M and Capital	
Meters	Ratemaking treatment of removed meters	
Update	Issues covered by update testimony, participation in update hearings, drafting brief on update issues	
OSBU	Operations Support Business Unit – includes Corporate Real Estate	
HR	Human Resources – pensions and benefits, medical costs, etc.	
Exec Comp	Executive Compensation – Long-term and short-term incentive payments, etc.	
RIIM	Reliability Investment Incentive Mechanism – SCE proposal in testimony; SCE and CCUE settlement; review of RIIM-related advice letters	
Peaker	Issues related to the McGrath Peaker – need and cost forecasts	

- Time entries that cover substantive issue work that cannot easily be identified with a specific activity code. In this proceeding the time entries coded # represent a very small portion of the total hours. TURN requests compensation for all of the time included in this request for compensation, and therefore does not believe allocation of the time associated with these entries is necessary. However, if such allocation needs to occur, TURN proposes that the Commission allocate these entries in equal 20% shares to the broader issue-specific categories described above that were most likely to have work covered by a # entry (TDBU, CSBU, OSBU, A&G and IT).
Comp – Time devoted to compensation-related pleadings.
Travel – Time devoted to travel related exclusively to work in this proceeding.

TURN submits that under the circumstances this information should suffice to address the allocation requirement under the Commission's Rules. Should the Commission wish to see additional or different information on this point, TURN requests that the Commission so inform TURN and provide a reasonable opportunity for TURN to supplement this showing accordingly.

B. Specific Claim*:

Claimed						CPUC Award		
ATTORNEY, EXPERT, AND ADVOCATE FEES								
Item	**Year**	**Hours**	**Rate**	**Basis for Rate***	**Total $**	**Hours**	**Rate**	**Total $**
Marcel Hawiger	2010	13.5	$350	D.11-09-037	$4,725.00	13.5	$350	$4,725.00
M. Hawiger	2011	277.0	$350	D.12-05-034	$96,950.00	277	$350	$96,950.00
M. Hawiger	2012	25.0	$375	See Comment 1, below.	$9,375.00	25	$375	$9,375.00
Robert Finkelstein	2010	21.25	$470	D.10-09-042	$9,987.50	21.25	$470	$9,987.50
R. Finkelstein	2011	586.5	$470	D.12-03-024	$275,655.50	579.07	$470	$272,162.90
R. Finkelstein	2012	47.5	$480	Res. ALJ-281	$22,800.00	45.45	$480	$21,816.00
Hayley Goodson	2010	1.5	$295	D.10-12-015	$442.50	1.5	$295	$442.50
H. Goodson	2011	232.75	$300	Pending in A.11-05-017	$69,825.00	232.75	$300	$69,825.00
H. Goodson	2012	34.25	$325	Pending in A.11-05-017	$11,131.25	34.25	$325	$11,131.25
Nina Suetake	2011	238.50	$295	D.12-05-033	$70,357.50	238.50	$295	$70,357.50
N. Suetake	2012	3.25	$315	See Comment 1, below.	$1,023.75	3.25	$315	$$1,023.75
Marybelle Ang	2011	121.4	$280	D.11-06-012 (for work in 2010)	$33,992.00	117.9	$280	$33,012.00
Thomas Long	2011	2.5	$520	Request pending in A.09-10-013	$1,300.00	2.5	$520	$1,300.00
William Marcus	2010	5.6	$250	D.12-03-024	$1,400.00	2.72	$250	$680.00
W. Marcus	2011	368.09	$250	D.12-03-024	$92,022.50	365.21	$250	$91,302.50

W. Marcus	2012	7.5	$260	See Comment 2, below.	$1,950.00	7.5	$260	$1,950.00
Gayatri Schilberg	2010	45.55	$200	D.12-03-024	$9,110.00	45.55	$200	$9,110.00
G. Schilberg	2011	499.33	$200	D.12-03-024	$99,866.00	499.33	$200	$99,866.00
G. Schilberg	2012	12.8	$205	See Comment 2, below.	$2,624.00	12.8	$205	$2,624.00
Jeff Nahigian	2010	73.0	$190	D.10-07-040	$13,870.00	73	$190	$13,870.00
J. Nahigian	2011	409.0	$195	See Comment 2, below.	$79,755.00	409	$195	$79,755.00
J. Nahigian	2012	3.25	$200	See Comment 2, below.	$650.00	3.25	$200	$650.00
Garrick Jones	2010	110.17	$140	D.12-03-024	$15,423.80	105.07	$140	$14,709.80
G. Jones	2011	673.53	$140	D.12-03-024	$94,294.20	646.70	$140	$90,538.00
G. Jones	2012	0.62	$150	Request pending in A.10-11-002 (filed 7/13/12)	$93.00	.31	$150	$46.5
Greg Ruszovan	2011	82.76	$195	D.12-03-024 (for work in 2010)	$16,138.20	82.76	$195	$16,138.20
Jim Helmich	2011	17.5	$195	D.12-03-024 (for work in 2010)	$3,412.50	16.10	$195	$3,139.50
John Sugar	2011	66.59	$200	See Comment 2, below.	$13,318.00	65.58	$200	$13,116.00
J. Sugar	2012	21.32	$205	See Comment 2, below.	$4,370.60	21.32	$205	$4,370.60
Kevin Woodruff	2011	11.5	$235	D.12-06-014	$2,702.50	11.5	$235	$2,702.50
Jack Pous	2011	238.0	$225	See Comment 2, below.	$53,550.00	238	$225	$53,550.00

J. Pous	2012	1.5	$225	See Comment 2, below.	$337.50	1.5	$230	$345.00
Sara Coleman	2011	13.0	$125	See Comment 2, below.	$1,625.00	13	$125	$1,625.00
Erin Ladd	2011	87.5	$75	See Comment 2, below.	$6,562.50	87.5	$75	$6,562.50
				Subtotal:	**$1,145,090.70**[2]		**Subtotal:**	**$1,086,584.40**[3]
OTHER FEES **Describe here what OTHER HOURLY FEES you are Claiming (paralegal, travel **, etc.):**								
Item	**Year**	**Hours**	**Rate**	**Basis for Rate***	**Total $**	**Hours**	**Rate**	**Total $**
Robert Finkelstein	2011	6.0	$235	½ 2011 hourly rate	$1,410.00	6	$235	$1,410.00
				Subtotal:	**$1,410.00**		**Subtotal:**	**$1,410.00**
INTERVENOR COMPENSATION CLAIM PREPARATION **								
Item	**Year**	**Hours**	**Rate**	**Basis for Rate***	**Total $**	**Hours**	**Rate**	**Total $**
Marcel Hawiger	2011	.75	$175	½ 2011 hourly rate	$131.25	.75	$175	$131.25
Robert Finkelstein	2011	.25	$235	½ 2011 hourly rate	$58.75	.25	$235	$58.75
Robert Finkelstein	2012	28.25	$240	½ 2012 hourly rate	$6,780.00	28.25	$240	$6,780.00
				Subtotal:	**$6,970.00**		**Subtotal:**	**$6,970.00**
COSTS								
#	**Item**	**Detail**			**Amount**	**Amount**		
1	Photocopies	Copies for testimony, pleadings, hearing room exhibits and other proceeding documents			$807.37			$807.37

[2] According to a telephone conversation with TURN Attorney Bob Finkelstein on July 25, 2013 this number should actually be $120,639.80 consistent with background support spreadsheets. Incorrect number in above spreadsheet doesn't impact TURN total on following page.

[3] Some excessive time was spent on internal meetings, review of other parties' testimony, and editing of TURN testimony. Therefore total amount claimed for attorney/expert fees is reduced by 2%. Please see the Comments section below for a more detailed explanation. The total before the 2% reduction is $1,108,759.50. The 2% reduction results in the total of $1,086,584.40.

2	Travel and Hotel	Plane fare, shuttle and hotel for TURN attorney covering evidentiary hearings in Los Angeles	$592.26		$592.26
3	Telephone	Calls relating to work on A.10-11-015	$60.89		$60.89
4	Postage	Mailing costs for pleadings	$67.20		$67.20
5	Courier	FedEx overnight delivery	$49.54		$49.54
6	Lexis/Nexis	Computerized Research	$660.31		$660.31
		Subtotal:	**$2,237.57**	**Subtotal:**	**$2,237.50**
		TOTAL REQUEST $:	**$1,131,257.37**	**TOTAL AWARD $:**	**$1,097,201.90**

*We remind all intervenors that Commission staff may audit their records related to the award and that intervenors must make and retain adequate accounting and other documentation to support all claims for intervenor compensation. Claimant's records should identify specific issues for which it seeks compensation, the actual time spent by each employee or consultant, the applicable hourly rates, fees paid to consultants and any other costs for which compensation was claimed. The records pertaining to an award of compensation shall be retained for at least three years from the date of the final decision making the award.

**Travel and Reasonable Claim preparation time typically compensated at ½ of preparer's normal hourly rate

Attorney	Date Admitted to CA BAR	Member Number
Marcel Hawiger	January 31, 1998	194244
Robert Finkelstein	June 13, 1990	146391
Hayley Goodson	December 5, 2003	228535
Nina Suetake	December 14, 2004	234769
Marybelle Ang	September 18, 2009	264333
Thomas Long	December 11, 1986	124776

C. TURN's Comments and Attachments on Part III:

Attachment or Comment #	Description/Comment
Attach 1	**Certificate of Service**
Attach 2	**Daily Time Records for Attorneys and Experts**
Attach 3	**Cost Detail**
Comment 1	**Hourly Rates for TURN Attorneys:** TURN seeks hourly rates for its staff attorneys at levels that the Commission has previously adopted for each individual's work in a given year, or at an increased level for 2012 consistent with Resolution ALJ-281. The following describes the basis for the requested rates that have not been

	previously awarded as of the date of this Request for Compensation. Marcel Hawiger: For Mr. Hawiger's work in 2012, TURN seeks an hourly rate of $375, an increase of 7.2% from the previously awarded rate of $350 for 2010 and 2011. The increase is the general 2.2% increase provided for in Resolution ALJ-281, plus the first of two 5% step increases available with his move in 2010 to the 13+ years experience tier. Hayley Goodson: For Ms. Goodson's work in 2011 and 2012, TURN has justified the requested hourly rates in a Request for Compensation pending in A.11-05-017, *et al.* The $5 increase for 2011 reflects a step increase while she was in the 5-7 years experience tier (subject to the cap for that tier in that year). The $25 increase sought for 2012 reflects her move to the 8-12 years experience tier. Rather than repeat the justification for the requested hourly rate, TURN refers the Commission to the pending request in A.11-05-017, *et al*. and asks that the relevant material be incorporated by reference as though full set forth here. Should the Commission wish to see the justification included in this request, TURN requests the opportunity to supplement or amend this request accordingly. Nina Suetake: For Ms. Suetake's work in 2012, TURN seeks an hourly rate of $315, an increase of 7.2% from the previously awarded rate of $295 for 2011. The increase is the general 2.2% increase provided for in Resolution ALJ-281, plus the second of two 5% step increases available with her move in 2009 to the 5-7 years experience tier.
Comment 2	**Hourly Rates for TURN Consultants:** For many of the consultants who worked with TURN on this matter, TURN seeks hourly rates at levels that the Commission has previously adopted for each individual's work in a given year, or at an increased level for 2012 consistent with Resolution ALJ-281. Below TURN more fully discusses the new hourly rates sought for the consultants whose work was so critical to TURN's substantial contributions in this proceeding. **JBS Energy:** -- William Marcus and Garrick Jones: JBS Energy increased the hourly rates for Mr. Marcus and Mr. Jones as of 1/1/12. For Mr. Jones, the increase from $140 (through 2011) to $150 was discussed in some detail in the Request for Compensation filed in A.10-11-002 on July 13, 2012.[4] Rather than repeat the justification for the requested hourly rate, TURN refers the Commission to the pending request in A.10-11-002 and asks that the relevant material be incorporated by reference as though full set forth here. Should the Commission wish to see the justification included in this request, TURN requests the opportunity to supplement or amend this request accordingly. For Mr. Marcus, JBS Energy increased Mr. Marcus's hourly rate as of January 1, 2012, by $10 to $260, an increase of 4% over the $250 rate it had charged for his work in each of the previous four

[4] The increase is justified in part based on Mr. Jones's experience warranting a move to the next tier the Commission has adopted for intervenor compensation purposes.

	years. JBS Energy last changed the hourly rate charged for his work in 2008, when his rate increased from $220 to $250. The Commission approved using the $250 rate for work performed in 2008 in D.08-11-053 (in the Sempra GRC A.06-12-009). In mid-September 2012, the Commission issued Resolution ALJ-281 adopting an across-the-board cost-of-living adjustment (COLA) that permits a 2.2% increase to previously authorized hourly rates. Had JBS Energy increased Mr. Marcus's 2012 hourly rate by 7.2%, TURN could have justified that rate by relying on the COLA plus a 5% increase as the first of the two "step" increases provided for in D.08-04-010 and reaffirmed in Resolution ALJ-281. Therefore TURN submits that the Commission should find Mr. Marcus's 2012 hourly rate of $260 to be reasonable due to its consistency with the COLA and a portion of the step increase provided for in those earlier decisions. Should the Commission wish to see further justification for this increase, TURN requests the opportunity to supplement or amend this request accordingly. -- Jeff Nahigian: TURN seeks an hourly rate of $195 for Mr. Nahigian's work during 2011 in this proceeding, equal to his actual billing rate during this period. This is an increase of $5 per hour from the $190 rate authorized for work in 2010. It is also an increase over the amount sought and awarded in R.09-08-009 for a very small number of 2011 hours.[5] The Commission first authorized the $190 hourly rate for Mr. Nahigian's work in 2008. In the compensation request addressed in the decision that adopted the $190 rate, TURN had requested a 2008 hourly rate of $195, consistent with the rate increase JBS Energy had implemented effective at the start of 2008. However, the Commission limited the increase to the 3% COLA increase plus a 5% step increase applied to the $175 hourly rate that had been adopted for work in 2007. Mr. Nahigian is a Senior Economist with over twenty years of experience in energy-related analysis. He holds a B.S. in Environmental Policy and Analysis and Planning from U.C. Davis, and has been with JBS Energy since 1986. Since then he has analyzed and sponsored testimony on a variety of cost-of-service and rate design issues, and AMI and a variety of demand response issues. Over the years he has also borne substantial responsibility for the review and position development for line extension issues and utility capital spending for corporate real estate forecasts. The Commission retained the $155-390 range for experts with more than 13 years of experience in 2011. Resolution ALJ-267. With approximately twenty years experience with JBS Energy, Mr. Nahigian would easily fall at least at the mid-point of that range (approximately $275). Again, as is typical for the rates JBS Energy charges for each of its firm members, the $195 rate for work performed in 2011 is substantially below the figure one would expect using the scale the Commission had in effect in 2011, and is within the bottom quartile for the ranges for experts with this level of experience. It is also below the rate produced if the Commission were to apply the "5% step increase" approach here (which would produce a $200 hourly rate). Mr. Nahigian's experience is most easily compared to that of his colleagues at JBS Energy. He has

[5] TURN's request for compensation in R.09-08-009, filed September 15, 2011, sought $190 as the hourly rate for Mr. Nahigian's 9.75 hours in 2011. This was due to an internal TURN error that overlooked the actual rate of $195 that JBS Energy billed TURN for his work in 2011. In D.12-06-036, the Commission awarded the requested rate for Mr. Nahigian's 2011 work. TURN has become aware that a similar mistake was made in the pending request for compensation in A.10-03-014, filed October 19, 2012, and intends to take steps to correct that mistake in that proceeding.

	several years more experience than Mr. Ruszovan (who has a $195 hourly rate authorized for 2011). He also has approximately the same amount of in 2011 than did Scott Cratty and Beth Kientzle of Murray & Cratty when the Commission awarded an hourly rate of $210 for work those individuals performed on behalf of TURN in 20**05** (D.06-09-011, in the SBC merger proceeding). The Commission should also approve the $195 rate for work performed in 2011 because it is the market rate that JBS Energy charges each of its clients for work performed by Mr. Nahigian during that year. The Commission has long recognized that JBS Energy is a unique and valued resource because the firm consistently provides first-rate analysis at cut-rate prices. Mr. Nahigian is typical of the firm, in that he brings decades of direct experience that permits him to provide high quality work on behalf of consumers, and the firm has set his hourly rate at a level far below what one would expect the market rate to be. If the Commission were to approve a lower rate for his work during that period, at some point it can reasonably expect that either JBS Energy will devote less time to Commission proceedings (in favor of more time devoted to work at its usual hourly rates) or TURN will continue to bear a shortfall in cost recovery even as we continue to rely on a firm that charges hourly rates far below what the market would bear for individuals of similar talent and experience. TURN submits that this information is more than sufficient for the Commission to grant the requested increase to Mr. Nahigian's hourly rate for 2011. However, should the Commission disagree and believe that it needs more information to support the request, TURN asks that we be given an opportunity to provide additional information before a draft decision issues on this compensation request. -- <u>John Sugar</u>: This is the first Request for Compensation that includes work performed by John Sugar, who joined JBS Energy in early 2011 after approximately 30 years with Sacramento Municipal Utility District (SMUD) and California Energy Commission (CEC). For work Mr. Sugar performed in 2011 and through August 2012, TURN seeks an hourly rate of $200; as of September 1, 2012, JBS Energy increased his hourly rate to $205. TURN seeks these rates because they reflect the market rates that JBS Energy charges all of its clients for work Mr. Sugar performs in 2011 and 2012, and because they are in the lowest quintile of the $155-$390 range the Commission has established for 2011 for expert witnesses and consultants with more than thirteen years experience. Mr. Sugar graduated with honors from the University of California, Santa Cruz, with an A.B. degree in economics in 1974. He earned an M.A. in Public Policy from the University of California, Berkeley in 1975. In 1980, he joined SMUD's Conservation Department, supervising program development and evaluation. In 1983, he moved to the Rate Department, developing experimental time-of-use rate programs, and assisting in financings. In 1985, Mr. Sugar joined the Resource Planning Department, developing methodologies to incorporate demand-side programs into the portfolio of resource options available to SMUD. In 1988, Mr. Sugar joined the CEC's Assessments Division, developing and implementing a least-cost methodology for Resource Planning in the Commission's Electricity Report 7. From 1989 through 1993, as Chief Resource Planner, Mr. Sugar was responsible for improving methodological collaboration between Commission staff and parties presenting alternative resource plans. From 1993 to 2011, he managed various efficiency initiatives at the Energy Commission, including managing technical and engineering staff responsible for analysis underlying New Construction Efficiency and Appliance Efficiency standards (1993-1998) and managing the CEC's programs providing Best Practices workshops and energy surveys to industrial users, as well as

	programs providing loans and technical assistance to local jurisdictions (1999-2011). Mr. Sugar has extensive experience preparing and presenting expert witness testimony on energy-related matters. He prepared and presented formal testimony to the CEC on topics related to the Electricity Reports and on New Construction Efficiency Standards cost-effectiveness, expected impacts and the Standards development process. Since joining JBS Energy he has presented testimony at the Commission regarding an SDG&E proposal to install utility-owned photovoltaics (testimony on behalf of UCAN) and a PG&E proposal for Green Option tariff (A.12-04-020). He has also played an instrumental role in helping to develop the testimony sponsored on behalf of TURN and otherwise assist TURN with its work in proceedings as varied as the SCE Catalina Water GRC (A.10-11-009), the Sempra TCAP (A.11-11-002), the Cal-Peco GRC (A.12-02-014), and the GRCs for the four major energy utilities (SCE – A.10-11-015; SCG/SDG&E A.10-12-005/006; and PG&E A.12-11-009). Mr. Sugar has also performed work with JBS Energy in regulatory proceedings in Texas and Arkansas. With more than thirty years of direct experience in energy regulatory matters in California, the vast majority of which were while on the staff of the CEC, the Commission should have no trouble authorizing an hourly rate for Mr. Sugar at the <u>upper</u> end of the $155-$390 range established for 2011 work by expert witnesses with more than thirteen years of experience. The $200 rate is in the <u>lowest</u> quintile of this range, once again affirming that JBS Energy charges rates that are very low by any standard. As with Mr. Nahigian (discussed above), Mr. Sugar's experience is most easily compared to that of his colleagues at JBS Energy. He has nearly the same years of experience as Mr. Marcus (who has a $250 hourly rate authorized for 2011), and more experience than Ms. Schilberg and Mr. Ruszovan (who have 2011 hourly rates of $200 and $195, respectively). Mr. Sugar has substantially more experience in 2011 than did Scott Cratty and Beth Kientzle of Murray & Cratty when the Commission awarded an hourly rate of $210 for work those individuals performed on behalf of TURN in 20<u>**05**</u> (D.06-09-011, in the SBC merger proceeding). And as TURN discussed regarding Mr. Nahigian's rate, the Commission should also approve the $200 rate for work performed in 2011, and the $205 rate for work performed after September 1, 2012 because they are the market rates that JBS Energy charges each of its clients for work performed by Mr. Sugar during those periods. The Commission has long recognized that JBS Energy is a unique and valued resource because the firm consistently provides first-rate analysis at cut-rate prices. Mr. Sugar's addition to the firm continues that tradition; he brings decades of direct experience that permits him to provide high quality work on behalf of consumers, and the firm has set his hourly rate at a level far below what one would expect the market rate to be. TURN submits that this information is more than sufficient for the Commission to grant the requested increase to Mr. Sugar's hourly rates for 2011 and post-September 1, 2012. However, should the Commission disagree and believe that it needs more information to support the request, TURN asks that we be given an opportunity to provide additional information before a draft decision issues on this compensation request. -- <u>JBS Energy 2012 Hourly Rates</u>: As discussed earlier, JBS Energy increased the hourly rate charged for Mssrs. Marcus and Jones as of the start of 2012. JBS Energy increased the hourly rates for Ms. Schilberg and Mssrs. Ruszovan, Nahigian, Sugar and Helmich as of 9/1/12. The increases are consistent with the 2.2% cost-of-living adjustment the Commission authorized for 2012 in Resolution ALJ-281. TURN only seeks approval of the increased rate for the 2012 hours of

Ms. Schilberg, Mr. Nahigian and Sugar, as neither Mr. Ruszovan nor Mr. Helmich recorded any 2012 hours for work on this matter.

Diversified Utility Consultants, Inc:

The Commission has previously awarded TURN intervenor compensation for work performed by Diversified Utility Consultants, Inc. (DUCI) on depreciation-related topics in GRCs. However, there has been no authorized rate for DUCI firm members in more than four years. Therefore, TURN is seeking to establish new rates for the members of the firm who worked on this proceeding. TURN requests hourly rates of $225 for Jack Pous, the firm's principal, $125 for Sara Coleman, a senior analyst with the firm, and $75 for the work of Erin Ladd, an analyst with the firm. These are the same rates that DUCI Energy billed TURN for his work during this period.

-- Jack Pous: As noted earlier, Mr. Pous is President of DUCI. Since 1972, Mr. Pous has worked steadily in the field of utility revenue requirement and ratemaking analysis, first as an employee of Kansas City Power & Light Company, then for ten years in an independent consulting engineering firm, and since 1986 with DUCI, a firm he helped create. As a principal of DUCI, Mr. Pous has presented and prepared numerous electric, gas, and water analyses in both retail and wholesale proceedings, with clients (including public utility commissions) throughout the United States. Appendix A of his prepared testimony (Exhibit TURN-1) sets forth a fuller statement of Mr. Pous's education, experience and qualifications, including a listing of the numerous proceedings in which he has sponsored testimony on depreciation and other topics before a variety of regulatory agencies, including this Commission.

Mr. Pous's qualifications and experience on the depreciation-related issue he addressed in this proceeding are directly comparable to those of William Marcus, the Principal Economist with JBS Energy, and Mike Majoros of Snavely, King, a consulting firm TURN has also used for expert witness services on depreciation-related matters. Mr. Pous's hourly rate of $225 in 2011 is $25 below the rate authorized for Mr. Marcus's work since 2008. This is approximately the same difference as existed in SCE's 2003 GRC, when the Commission found the then-requested rate for Mr. Pous's work in 2004 did not exceed the hourly rates for similarly qualified experts and was reasonable. D.05-06-031, at 44-45. For Mr. Majoros, the Commission approved an hourly rate of $240 for work performed in 2005. D.06-10-018, at 41-42. Given that Mr. Pous's hourly rate continues to be lower than Mr. Marcus's current rate, lower than the rate authorized for a similar witness addressing the same topic for TURN in 2005, and that the rates for all of these top-notch, very experienced expert witnesses are in the lower 50% of the range the Commission has established for intervenor compensation purposes, the Commission should have no trouble finding Mr. Pous's rate of $225 reasonable for work he performed in 2011 and 2012 in this proceeding.

-- Sara Coleman: Ms. Coleman is a Senior Analyst with DUCI, and has been with the firm since 1996. The firm's market hourly rate for her services is $125. In this proceeding she provided Mr. Pous with analytical support for drafting of the firm's testimony. In other matters she also provides project management, litigation and operations support. In D.00-09-068, the Commission approved an hourly rate of $100 for work Ms. Coleman performed in 1998. In D.06-10-018, the Commission adopted an hourly rate of $160 for similarly-qualified and –experienced individuals for work performed in 2005. In 2011 Ms. Coleman had more than thirteen years' experience, but her $125 hourly rate is below the $155 low end of the range for persons providing expert witness services. The Commission should find the requested hourly rate reasonable.

-- Erin Ladd: Ms. Ladd is an Analyst with DUCI, an entry-level position with the firm, with an

	hourly rate of $75. She provided technical and analytical assistance to Mr. Pous in the development of his expert testimony and preparation of cross-examination materials for the evidentiary hearings. In D.06-10-018 (at 42-43), the Commission authorized an hourly rate of $75 for an individual providing similar support services to a depreciation expert witness in 2005. The $75 hourly rate is below the low end of the range ($125-$185) for persons providing expert witness services with 0-6 years experience in 2011. The Commission should find the requested hourly rate reasonable.

D. CPUC Disallowances & Adjustments:

#	Reason
1. Disallowance for failure to make a substantial contribution to issue #4, Catalina Diesel.	As stated on pages 91 and 92 of the final decision, TURN's write off argument was unpersuasive. Therefore, TURN did not make a substantial contribution in this area and some impacted hours are reduced by 10%.
2. Disallowance for unproductive effort/excessive hours on issue #23, Executive Officer Compensation.	TURN's recommendations primarily followed logic of 2009 decision so excessive review and analysis, as reflected by hours, appears to be unnecessary. Some impacted hours are reduced by 20%.
3. Disallowance for failure to make a substantial contribution to issue #24, Pension Benefits.	As stated on page 471 of the final decision, for the medical escalation rate, the Commission adopted a figure between what SCE and TURN offered based on other evidence (7.5%). TURN raised the escalation issue but did not make a substantial contribution and some impacted hours are reduced by 50%.
4. Disallowance for failure to make a substantial contribution to issue #31, Corporate Resources Capital Projects.	As stated on pages 577 and 578 of the final decision, the Commission did not adopt or agree with TURN's position on the Rosemead Data Center (RDC). The final $4.5 million disallowance was approved for other reasons. TURN did not make a substantial contribution.
5. Disallowance for unproductive efforts.	Some portion of SONGs hours were reduced by 20% since they were not a significant focus of the proceeding.
6. Disallowance for unproductive efforts.	Hours related to issues raised by Port of Long Beach were disallowed because they were outside the scope of the proceeding.
7. Disallowance for excessive hours.	Some excessive time was spent on internal meetings, review of other parties' testimony, and editing of TURN testimony. Therefore total hours are reduced by 2%. At the same time, Commission appreciates efficient organization of claim (e.g., allocation of hours by issue) and coding to facilitate easier interpretation and evaluation of time spent on specific activities.
8. Adoption of Mr. Hawiger's 2012 hourly rate.	After reviewing TURN's comments as to why Mr. Hawiger should be awarded a rate of $375 per hour for work completed in 2012, the Commission finds TURN's rationale to be reasonable. This rate takes into consideration the 2.2% COLA, and is reflective of Mr. Hawiger's 13+ years of experience.

9. Adoption of Ms. Goodson's 2011 and 2012 hourly rates.	After reviewing TURN's comments and Ms. Goodson's credentials, the Commission awards Ms. Goodson the rates of $300 and $325 per hour for the years of 2011 and 2012.
10. Adoption of Ms. Suetake's 2012 hourly rate.	After reviewing TURN's comments and Ms. Suetake's credentials, the Commission awards Ms. Suetake the rate of $315 per hour for work completed in 2012.
11. Adoption of Mr. Jones' 2012 hourly rate.	After reviewing TURN's comments and Mr. Jones' credentials, the Commission awards Mr. Jones with the rate of $150 per hour for work completed in 2012.
12. Increase in 2012 hourly rates.	Abiding by Resolution ALJ-281, 2012 hourly rates have been raised to reflect the 2.2% COLA adopted by the resolution.

PART IV: OPPOSITIONS AND COMMENTS

A. Opposition: Did any party oppose the Claim?	No

B. Comment Period: Was the 30-day comment period waived (*see* Rule 14.6(2)(6))?	Yes

FINDINGS OF FACT

1. The Utility Reform Network has made a substantial contribution to D.12-11-051.

2. The requested hourly rates for TURN's representative are comparable to market rates paid to experts and advocates having comparable training and experience and offering similar services.

3. The claimed costs and expenses are reasonable and commensurate with the work performed.

4. The total of reasonable contribution is $1,097,201.90.

CONCLUSION OF LAW

1. The Claim, with any adjustment set forth above, satisfies all requirements of Pub. Util. Code §§ 1801-1812.

ORDER

1. The Utility Reform Network is awarded $1,097,201.90.

2. Within 30 days of the effective date of this decision, Southern California Edison Company shall pay The Utility Reform Network the total award. Payment of the award shall include interest at the rate earned on prime, three-month commercial paper as reported in Federal Reserve Statistical Release H.15, beginning April 10, 2013, the 75th day after the filing of Claimant's request, and continuing until full payment is made.

3. The comment period for today's decision is waived.

4. This decision is effective today.

Dated August 15, 2013, at Carmel-by-the-Sea, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
CARLA J. PETERMAN
Commissioners

APPENDIX

Compensation Decision Summary Information

Compensation Decision:	D1308022	**Modifies Decision?**	**No**
Contribution Decision(s):	D1211051		
Proceeding(s):	A1011015		
Author:	ALJ Melanie M. Darling		
Payer(s):	Southern California Edison Company		

Intervenor Information

Intervenor	Claim Date	Amount Requested	Amount Awarded	Multiplier?	Reason Change/Disallowance
The Utility Reform Network	1/25/13	$1,131,257.37	$1,097,201.90	No	Unproductive Efforts/Excessive Hours; Resolution ALJ-281; Failure to Make a Substantial Contribution.

Advocate Information

First Name	Last Name	Type	Intervenor	Hourly Fee Requested	Year Hourly Fee Requested	Hourly Fee Adopted
Marcel	Hawiger	Attorney	TURN	$350	2010	$350
Marcel	Hawiger	Attorney	TURN	$350	2011	$350
Marcel	Hawiger	Attorney	TURN	$375	2012	$375
Robert	Finkelstein	Attorney	TURN	$470	2010	$470
Robert	Finkelstein	Attorney	TURN	$470	2011	$470
Robert	Finkelstein	Attorney	TURN	$480	2012	$480
Hayley	Goodson	Attorney	TURN	$295	2010	$295
Hayley	Goodson	Attorney	TURN	$300	2011	$300
Hayley	Goodson	Attorney	TURN	$325	2012	$325
Nina	Suetake	Attorney	TURN	$295	2011	$295
Nina	Suetake	Attorney	TURN	$315	2012	$315
Maybelle	Ang	Attorney	TURN	$280	2011	$280
Thomas	Long	Attorney	TURN	$520	2011	$520
William	Marcus	Expert	TURN	$250	2010	$250
William	Marcus	Expert	TURN	$250	2011	$250
William	Marcus	Expert	TURN	$260	2012	$260
Gayatri	Schilberg	Expert	TURN	$200	2010	$200

California Public Utilities Commission
Docket A.13-11-003 SCE 2015 GRC

A Review of Pole Costs Requested by Southern California Edison Company

A Review of Pole Costs Requested by Southern California Edison Company (PUBLIC)

Prepared testimony of
Gayatri Schilberg
and William B. Marcus
JBS Energy, Inc.
311 D Street
West Sacramento
California, USA 95605
tel. 916.372.0534

on behalf of
The Utility Reform Network

California Public Utilities Commission
Docket A.13-11-003 SCE 2015 GRC

August 25, 2014

Testimony of Gayatri Schilberg and William B. Marcus

I. Introduction and Summary

This testimony was developed and written in largest part by Gayatri M. Schilberg, Senior Economist at JBS Energy. Due to extenuating circumstances, it was completed by and under the supervision of William B. Marcus, Principal Economist at JBS Energy.[1] Over Ms. Schilberg's more than 20 years of testifying at the CPUC, she has covered many topics including pole inspection and maintenance issues, pole attachment fees, and pole costs. In addition she represented TURN in the proceedings that created GO 165, and in early phases of the Safety proceeding (R.08-11-005). Ms. Schilberg's qualifications appear in Attachment 1.[2]

This testimony addresses pole-related issues in SCE's GRC showing, primarily SCE's proposed Pole Replacement Program (PLP) but also the Aged Pole Replacement Program and other pole issues. TURN recommends reducing 2013-2017 capital spending by $645 million and increasing joint pole credits (which reduce O&M expenses in Account 583.12) by $3.8 million.

With regard to the PLP, TURN offers the following observations:

- **The Associated Costs are Huge**

As presented by SCE, the PLP would be a huge capital undertaking, aiming to replace almost 20% of SCE's entire pole inventory in the next decade, and requiring $3 billion in capital outlay over 11 years. Annual revenue requirements for this program alone are likely to reach over half a billion dollars per year by 2026, in

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[1] TURN looks forward to Ms. Schilberg sponsoring the testimony during the upcoming evidentiary hearing. However, in the event that this is not possible, Mr. Marcus will sponsor the testimony.

[2] Mr. Marcus's qualifications are set forth in the separate testimony already served on behalf of TURN addressing an array of GRC issues other than pole-related issues.

addition to SCE's spending on normal breakdown/emergency and deteriorated pole programs.

- **In Order to Achieve An Equitable Allocation of PLP Costs Among Pole Users, A PLP-Specific Allocation Must Be Developed Rather Than The Existing Method of Sharing Costs of Pole Replacements.**

The existing practices and rules regarding rental of pole attachment space were developed in the context of how to make available <u>excess</u> capacity on poles. Those practices and rules do not contemplate large scale system replacements or expansions to accommodate overloading by attachments. Under the cost-sharing arrangements that apply to non-PLP pole replacements, SCE ratepayers often bear the preponderance of the cost, even where the replacement is undertaken for reasons having little or nothing to do with SCE's provision of electrical service to its customers. This is even true in cases where, but for the non-SCE attachments, SCE would have a pole that continues to meet desired loading standards and adequately served its electric needs.

- **Pole Replacement Is Not The Only Option In The Face of Overloading; For Example, SCE has the Right to Request Removal of an Attachment**

SCE's PLP proposal seems to presume that replacing an overloaded pole is the only option available to SCE. But in some cases, the overloaded condition could be remedied by reducing the load, by removing attachments.[3] SCE seems to have developed its proposal based on an assumption that its options are limited to those that would not disrupt attachments. The Commission should make clear to SCE that it should put electric service first and, to that end, should seek out options that permit it to continue to provide safe and reliable electric service without incurring costs of pole replacements, such as removing attachments where overloaded conditions would not exist but for the attachments. And the need for any remediation and replacement caused by the attacher should not result in costs borne by SCE's ratepayers.

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[3] TURN notes that under the attachment contracts negotiated with CCTA (California Cable & Telecommunications Association), there are many situations where SCE can give notice to an attacher that its license for an attachment will be revoked absent the attacher taking steps (and bearing the associated costs) to remediate the situation.

In many circumstances a pole attacher would have several other alternatives in the face of an overloaded condition, including choosing another route for its facilities or combining attachments to eliminate the loading condition. Some wireless attachers can attach to buildings or other structures, rather than to SCE poles. Replacement of the pole is not the only alternative in these cases, and these options should be explored fully.

- **The PLP is a One-Time Catch-up Program**

For many reasons, the SCE PLP represents a "catch-up" pole replacement effort to redress many aspects of poles and pole loading that SCE had not fully identified or recognized before. Despite its efforts in recent years to comply with existing inspection and pole load standards for 100% of its poles, SCE suddenly realized that it had a system-wide pole-loading problem that warrants replacement of 20% of those poles. For such a unique one-time situation that has potentially massive cost consequences, the Commission should authorize a special catch-up fee that SCE will collect from the joint pole owners and attachers for the poles needing replacement. Such an SCE-specific fee for this SCE-specific program is consistent with the shared cause of the need for replacement (including not just the load of the attachment, but gaps in data regarding the number and size of attachments), and with the shared benefit that all pole attachers will realize from the safer loading standards implemented in hazard areas.

- **Disallow Costs For The Aged Pole Replacement Program**

The Aged Pole Replacement Program is a make-work program to ramp up for PLP, and the logical foundation for this program is faulty. The Commission should reject this program in its entirety. It is imprudent to replace poles simply because they are old, if they are otherwise meeting inspection and loading standards. This constitutes unnecessarily shortening the life of a working asset.

A final note about confidential data – SCE has labeled as "confidential" much of the data upon which this testimony relies, thus many of the facts may not be accessible to all interested parties. This situation inhibits a full debate on the many public policy issues that are covered here.

II. Context for SCE's PLP Proposal

The Commission needs to consider SCE's PLP proposal in the context of prior decisions and orders that address pole overloading and related issues, as well as surrounding events.

SCE claims it is "required to permit certain telecommunications utilities to attach to its poles through a rental agreement" due to the mandatory access policy implemented in D.98-10-058. (SCE-03, Vol. 6, Part 2, p. 6.) This is the decision issued in the Commission's rulemaking regarding opening the local exchange market to competition among telecommunications companies (R.95-04-043/I.95-04-044). And while the decision adopted rules requiring the electric utilities such as SCE to provide access to their poles, it also addressed the need to restrict such access where necessary due to safety and reliability concerns:

> We generally agree that the incumbent utility, particularly electric utilities, should be permitted to impose restrictions and conditions which are necessary to ensure the safety and engineering reliability of its facilities. In the interest of public health and safety, the utility must be able to exercise necessary control over access to its facilities to avoid creating conditions which could risk accident or injury to workers or the public. The utility must also be permitted to impose necessary restrictions to protect the engineering reliability and integrity of its facilities.[4]

A few months later the Commission issued D.99-06-080, addressing PG&E's response to severe wind and rainstorms that occurred in December 1995. The damage to PG&E's system was attributed in part to pole overloading conditions. After noting that the record in that proceeding highlighted the important safety and reliability implications of proper wood pole loading, the Commission stated its intention to open a new rulemaking in which it would consider "the limited issue of revision of wood pole minimum safety factors and their replacement or reinforcement."[5]

Nine years later, the Commission opened a rulemaking to consider revising and clarifying its "regulations designed to protect the public from potential hazards,

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[4] D.98-10-058, p. 72.

[5] D.99-06-080, 1999 Cal. PUC LEXIS 430, *50-51 and 54.

including fires, which may be caused from electric utility transmission or distribution lines or communications infrastructure providers' facilities in proximity to the electric overhead transmission or distribution lines." R.08-11-005 (p. 1). The initial order identified pole overloading as one of the issues the Commission intends to consider, including "clarifying, refining or developing additional rules to mitigate the potential dangers of pole overloading" (pp. 12-13). And in D.14-02-015 issued in that rulemaking, the Commission addressed circumstances where a Grade B wood pole (that is, a single-use pole that hosts only electric facilities) becomes a Grade A wood pole subject to higher safety factors when the first communications infrastructure provider (CIP) attaches facilities to the pole. The CIPs had argued that it would be unfair for the first attacher to bear the costs of ensuring that the pole reaches a safety factor of at least 4.0, while subsequent attachments would only need to achieve a safety factor of 2.67. The Commission responded by suggesting the devising of "a cost-sharing arrangement whereby entities that attach to a Grade B pole that has been upgraded to Grade A standards by the first attaching CIP bear a fair share of the upgrade costs" (D.14-02-015, p. 33). However, since no party had proposed a cost-sharing arrangement in that proceeding, the Commission did not address the matter further.

In recent years there have been several events that involved pole overloading concerns. SCE's testimony cites the Malibu Canyon Fire of 2007 and the San Gabriel Valley windstorm of 2011, both of which involved concerns regarding pole overloading (SCE-03, Vol. 6, Pt. 2, p. 7). And in recent months the Commission has initiated a rulemaking into issues regarding adding Commercial Mobile Radio Service (CMRS) carriers facilities to existing poles (R.14-05-001), and is considering a request to permit video service providers (such as Google Fiber) to have the same access to electric utility poles as do cable operators (in R.06-10-005). Each of these requests would have pole loading implications.

III. SCE Pole Loading Program Proposal and Underlying Costs

In recent years, some SCE poles failed during fire/wind events and were subsequently found to have been overloaded at the time of the failure. SCE now proposes a Pole Loading Program (PLP) that will assess all of its poles and remediate those that do not meet designated safety factors (SCE 3 v. 6 pt 2, p. 12). Based on a study of roughly 5,000 of its 1.4 million poles, SCE concludes that 19% of poles are expected to require replacement (SCE 3 vol. 6 pt. 2, p.26), with 3% needing other repairs (SCE 3 v. 6 pt. 2 p. 22 and WP 76). SCE plans to assess the pole loading of its entire inventory over the 7 years 2014-2020 (with first priority to high risk areas), with remediation planned over a total of 12 years (SCE 3 v. 6 pt 2 p. 13).

A. Revenue Requirement Consequences of the PLP Program as Proposed

The cost consequences of this Pole Loading Program (PLP) are significant. SCE estimates $38 million O&M in the test year for assessments and repairs, as well as $1 billion from 2014-2017 for capital investments (net of costs related to the Malibu settlement and contributions from joint pole owners) (SCE 3 vol 6 pt. 2 p. 18.) This request is in addition to $1.5 billion in capital 2013-2017 for deteriorated and emergency/breakdown poles (includes aged poles) in the GRC request also.

If pole replacements in later years occur at the levels projected for 2014-2017, the cost of this program could easily reach $3 billion in capital over the 12 years of planned replacements. Thus, the consequences of this program for revenue requirements start off substantial, and then will increase at an increasing rate after this GRC cycle. For the capital portion only, SCE roughly estimates a revenue requirement increase of $35 million due to PLP capital between 2015 and 2016, and a $60 million revenue requirement increase between 2016-2017. (TURN DR 5 Q 29). These amounts would increase significantly each year thereafter, culminating in a stand-alone revenue requirement for this program in excess of $500 million by 2026.[6] TURN recognizes that the revenue consequences could change depending on the accuracy of SCE's initial assumptions about the PLP, such as the number of poles warranting replacement or the replacement cost per pole. But there is no disputing that acceptance of this program as

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[6] Revenue requirements estimated based on SCE 62 Q 13b and TURN calculations extending the parameters of that data response to 2026 in nominal dollars and correcting a spreadsheet programming error in the subtraction of accumulated deferred income taxes from rate base originally made by Edison. TURN requested that Edison conduct this analysis so that there would not be any controversy regarding the numbers, but Edison refused. TURN DR 74 Q.2.

proposed by SCE will set up a timetable of hugely increasing revenue requirements to be met by ratepayers.

B. Cost of a Pole Replacement

A distribution pole replacement capital cost of $12,130[7] includes the cost of removal[8] as well as division overhead (29%) and corporate overhead (10%) (TURN DR 62 Q 13a.) This cost does not include the contributions from joint owners, which is separately accounted for (TURN DR 5 Q 11c). In addition to the capital costs, SCE forecasts capital-related expenses (0.95% for transmission poles and 1.02% for distribution poles) as a function of the pole replacement costs (SCE 3 v. 6 pt 2 p. 24 and WP 109).[9]

The components of SCE's distribution pole cost are examined in the table below. Some costs show large increases, far beyond inflation, between 2009 and 2012 (see the last column of the table). Especially worrisome are the large increases in contractor costs (21% in distribution poles and 122% in transmission from 2009-2012). Also puzzling are the large percentage cost increases in "other" for distribution poles, as well as a 17% increase after inflation in department overhead.

SCE explains the increase in transmission contractor costs in 2012 as due to an increased use of contractors relative to SCE labor (TURN DR 101 Q 2b). This increase is sizeable -- $1,820 per pole between 2011 and 2012 alone, largely accounting for the increase in total transmission pole costs of $1,737, as the corresponding decline in SCE labor costs was relatively small.

SCE notes that the "materials" category includes the poles supplied to contractors, "overhead" category includes allocated costs and overheads, such as shared services

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[7] Transmission poles cost $19,800 in $2012 (SCE 3. V. 6 pt 2, p. 27).

[8] TURN DR 5 Q 11b. As stated in TURN DR 5 Q 12d, roughly 28% of distribution pole costs in 2012 were associated with cost of removal, and 25% of transmission pole costs. The costs of removal cut across multiple categories of costs shown in Table 1, including contractor costs (TURN DR 101 Q 2a).

[9] Such items included in the expense include insulators and, where the pole itself is not being replaced, costs of replacement of cross arms and brackets (SCE 3 v. 10, p. 27).

(vehicles, procurement services, mapping/drawing management, and T&D support costs such as planning, scheduling, and field accounting). The "Other" category includes miscellaneous costs such as employee expenses, lodging and mileage as well as deeded assets (TURN DR 101 Q1a-1e). We see no explanation for a 265% increase in "other" costs from 2009-2012.

Table 1: SCE Unitized Pole Cost Data, 2012$

	2009	2010	2011	2012	2009-2012 as % of 2009
	Distribution Pole Unit Cost (Constant 2012$)				
Contractor	5,459	6,689	6,406	6,612	21%
Labor	823	590	690	829	1%
Material	806	918	805	875	9%
Other	80	75	120	292	265%
Overhead	3,016	3,465	3,088	3,515	17%
Total	10,184	11,737	11,109	12,123	19%
	Transmission Pole Unit Cost (Constant 2012$)				
Contractor	3,922	6,376	6,880	8,700	122%
Labor	3,561	3,900	2,735	2,508	-30%
Material	3,536	4,667	3,739	3,853	9%
Other	809	414	320	354	-56%
Overhead	3,910	4,849	4,032	4,021	3%
Total	15,738	20,206	17,706	19,436	23%
Source: TURN 5 Q 12 b and TURN calculations					

SCE needs to do better containing these costs. Apparently SCE's strategy of using more contractor labor is not a bargain for ratepayers. If there is going to be a 12-year program of fixing poles, perhaps Edison needs more employees and fewer contractors doing this capital work. TURN recommends the average of 4 years' of recorded costs as the basis for forecasting and as an incentive to rein in costs on the expensive pole replacements. The 4-year average cost for distribution poles is $11,288, an 11% increase in real dollars over 2009. The 4-year average for transmission poles is $18,272, a 16% increase in real dollars over 2009. Adopting TURN's recommendation constitutes a 7% reduction from SCE's cost forecast for distribution poles in 2015, and a 6% reduction in SCE's cost for transmission poles.

See Section VIII below for the financial consequences of this recommendation.