SUPPORTING DOCUMENTS FOR
DIRECT TESTIMONY OF MICHAEL BROWN

VOLUME 2
(Exhibits 8-17)

Expert Report on Issues Affecting Small Businesses

Testimony of Michael Brown

on behalf of
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California Public Utilities Commission
Application 12-11-009
May 16, 2013

SUPPORTING DOCUMENTS FOR
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Exhibit 8

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	PG&E rate schedule	PG&E's actual 2011 gas sales Revenues in 000's	PG&E's 2012 natural gas sales forecast in 000's	PG&E's estimate of 2012 Distribution-Level Functions(b) in 000's
Small Commercial	G-NR1	526,415	792,357	240,750
Large Commercial	G-NR2	32,578	74,543	7,778

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Exhibit 9

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Price Volatility

Background

For roughly 15 years, from 1985 until 2000, natural gas prices at the wholesale level were very stable, fluctuating around $2.00 per million Btu (MMBtu). *In fact, when inflation is considered these prices actually fell in real terms. Since the winter of 2000–01, however, price* fluctuations have been dramatic. Wholesale prices reached $10.00 per MMBtu in the winter of 2000–01, retreated to the $2.00 level the following winter, but approached the $10.00 level again in the winter of 2002–03. In 2005, prices rose throughout the summer, spiked sharply to about $15 MMBtu in response to the damage caused by multiple hurricane landings and an early cold winter. Prices, however, have fluctuated in the $4 to $6 range for most of 2006, with ample supplies available in storage. Natural gas prices declined sharply in 2008, and are below $4.00 in early 2009 in response to increased supplies and reduced economic activity.

Volatility at the wholesale level ultimately results in volatility at the retail level. A lack of predictability makes it very difficult for homeowners and businesses to budget and pay for their natural gas service. It also has negative impacts on gas utilities, resulting in unhappy customers, less demand for their service and greater uncollectible accounts. Natural gas utilities do not profit from volatile prices—payments for natural gas ultimately flow back to the producer of the gas, utilities earn a regulated return for shipping the gas. Gas utilities can, and do, ease some of the volatility faced by their customers through practices such as levelized billing, fixed price contracting and hedging of their gas supply portfolio.

AGA Viewpoint

The fundamental cause of price volatility is the fact that demand for natural gas can change very rapidly as a result of changes in weather or other key variables. Supply changes, on the other hand, occur more slowly, although the recent increase in supply from shale formations has been relatively rapid.

AGA believes the problem of price volatility is best addressed by increasing the availability of natural gas through greater domestic gas supplies, new sources of domestic gas such as Alaska or currently restricted offshore areas, increased imports of gas from Canada, or from other countries via LNG. The natural gas resource base is abundant, and price volatility can be reduced when access to the resource base is not restricted. State utility commissions are encouraged to support programs proposed by natural gas utilities that would ease the burden of volatility on consumers, such as long-term fixed price contracts, hedging and the construction of new gas supply infrastructure. Congress can ease the burden of higher energy prices on the most vulnerable by increasing funding for LIHEAP.

Additional information: Avoiding the Wild Ride: Ways to Tame Natural Gas Price Volatility (AGA, 2003; www.aga.org)

AGA Contact: Chris McGill, Vice President, Policy Analysis, (202) 824-7134; Bruce McDowell, Director Policy Analysis,(202) 824-7131

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Exhibit 10

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Pipeline Safety Enhancement Plan Overview

September 1, 2011

Pipeline Safety Enhancement Plan (PSEP) Overview

The Pipeline Safety Enhancement Plan (PSEP)...

- Reflects new regulatory requirements which establish a known margin of safety across PG&E's gas transmission system
- Incorporates lessons from the San Bruno accident, NTSB recommendations, Independent Review Panel findings, and industry benchmarking
- Has been shared with or incorporates feedback from key regulators, utilities and other interested parties
- Seeks funding for Phase 1 work (2011-2014) only— with Phase 2 costs to be addressed in future proceeding
- Includes shareholder funding of all 2011 Plan work
- Excludes significant San Bruno-related shareholder spending to-date

PSEP- Key Features

- **Assesses and upgrades all PG&E gas transmission pipeline (5,786 miles) to modern safety standards**
- **Phase 1 (2011-2014) upgrades over 1,200 miles of pipe and 228 valves:**
  - Replace or strength test 969 miles of pipe in the most populous areas
  - Retrofit for in-line inspection (ILI) 199 miles and ILI 234 miles
  - Automate 228 valves
  - Validate and modernize gas transmission asset records
- **Phase 2 (2015 forward) addresses remaining gas transmission system**
- **Continues interim safety measures to assure public safety until pipeline modernization work is completed**
  - MAOP validation
  - Increased leak surveys and patrols
  - Pressure reductions as necessary

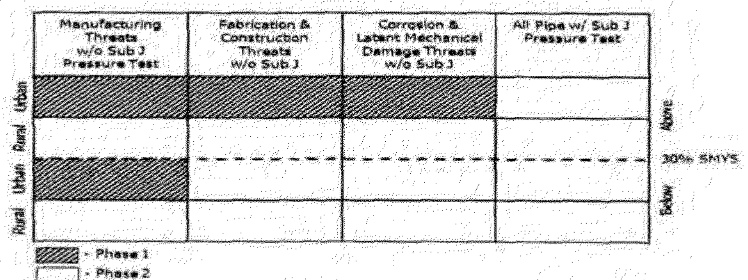
PSEP Work Streams

Work Streams	Objective
Pipe Modernization	Assure every gas transmission pipeline operates at or below proven, tested and verified safe operating pressure, "margin of safety" through • Strength Testing • Pipe Replacement • Pressure Reductions • Engineering assessments, MAOP Validations
Valve Automation	Facilitate emergency response to minimize the potential consequences of a natural gas fueled fire
Records Integration	Reflect the NTSB's recommendation for a new standard of "traceable, verifiable and complete" gas transmission records
Interim Safety Measures	Increase public safety of PG&E's gas transmission system prior to completing the work proposed

Pipeline Modernization

Pipeline Work Prioritization

- Targets pre-1970 pipe segments that have not been strength tested
- Uses ASME, industry-recognized pipeline threats, physical pipeline attributes, Class location, and operating specified minimum yield strength (SMYS) to define action
- Targets "Urban areas" all Class 2,3,4 and Class 1 HCA w/ high potential impact on people and property
- Project prioritization (annual work plans) based on Class location, HCA, PIR, and customer and public impacts



Valve Automation

Valve Work Prioritization

- Targets large diameter/high pressure pipelines located within high population density areas
- ~ 60 percent of Phase 1 automation miles located in the Peninsula/East Bay/South Bay

  Project prioritization based PIR, HCA density and geographic area
- Includes additional SCADA information, tools, and training for gas operators for early detection and quick response to pipeline rupture events

Valve Automation Decision Tree Outcome Summary				
Valve Location	Class 4 pipe segments PIR* > 100 ft.	Class 3 pipe segments PIR > 200 ft.	Class 3 pipe with > 50% HCA , PIR > 150 ft	Active fault, Class 3 or 4 or HCA, PIR > 150 ft
Phase 1 Outcome	**200 Remote Control Valves (PIR > 300, Class 3&4 HCA)** **28 Automatic Shutoff Valve (high threat earthquake fault crossings)**			

* PIR is defined as the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property

PSEP Phase 1 Scope

Over 1,200 miles of pipe upgraded and 228 valves automated 2011-2014

Work Streams	2011	2012	2013	2014	Phase 1
Strength Testing*	236 miles**	185 miles	204 miles	158 miles	783
Pipeline Replacements	0.3 miles	39 miles	64 miles	82 miles	186
ILI Upgrades	--	78 miles	121 miles	--	199
In-line Inspections	--	--	78 miles	156 miles	234
Valve Automation	29 valves	46 valves	90 valves	63 valves	228
Records Integration	Data Validation, MAOP Calculations, Integrated Asset & Work Management				
Interim Safety Measures	Pressure Reductions, Leak Surveys, Aerial Patrols				

* Mileage reflects actual miles pressure tested
** 2011 strength test miles as of June. 2011 total may change due to records validation efforts

PSEP Phase 1 Costs

PG&E Proposes 2011-2014 PSEP Costs of $2.2 B over 4 years

Forecast Costs in $MM	Shareholder Funded Costs	PSEP Costs Funded in Rates	
	2011	2012-2014	
Cost Categories	**Expense***	**Capital**	**Expense**
Pipeline Modernization	$123	$895	$285
Valve Automation	$2	$120	$9
Records Integration	$56	$96	$127
Interim Safety Measures	--	--	$3
Program Management	$1	$20	$11
Contingency	$39	$237	$92
PSEP Total Costs	**$222**	**$1,368**	**$527**

* For 2011, in addition to expense, shareholders to pay capital costs ($1.4MM) for projects put in-service

PSEP Shareholder Allocation

Shareholders fund a substantial portion of PSEP and related safety enhancement costs

	2010	2011	2012	2013	2014	Total
2011 Implementation Plan Work*	–	$222	–	–	–	$222
Validation & Testing Post 1970 Pipeline						
Post-1970 MAOP Validation	$0.1	$39	$36	$11	–	$86
Post-1970 Pressure Testing	–	$1	$7	$2	$3	$13
Non-Implementation Plan Costs**	$63	$152	***	***	***	$215
Total Shareholder Cost Allocation	$63	$414	$43	$13	$3	$536

* Includes $220.5 MM in forecast expense and $1.4 MM forecast capital by EOY 2011.

** Includes gas records gathering, leak surveys and repair, emergency response, and responding to data requests from CPUC, NTSB and others.

*** Non-Implementation Plan Cost are not forecasted for 2012 and beyond but are expected to be significant

PSEP Cost Approach

Proposes to put costs of new safety programs and standards not previously required into rates beginning in 2012.

Not in rates:

- Costs directly related to the San Bruno accident
- Non-Implementation Plan activities
- Work already included in 2011 GT&S Rate Case funding
- Pressure testing or validation for post-1970 pipe

Cost Recovery Approach Includes

- 2011 PSEP costs paid by shareholders
- Cost targets for expense and capital w/mid program adjustment request mechanism
- Use of funds limited to PSEP
- Customers pay only for capital projects put in-service
- Expense dollars not spent on PSEP returned to customers after 2014
- Semi-annual reporting for funds budgeted vs. spent, and project status

PSEP Revenue Requirement

- 2011 revenue requirement funded by shareholders
- 2011-2014 revenue requirement: $768MM for 4 years

Phase 1 Plan Incremental Annual Rev. Req.					
($ in millions)	2011**	2012	2013	2014	Total
Total RRQ	0	$247	$221	$300	$768

* Assumes non-core customers pay small commercial procurement rates.
** 2011 RRQ (approx. $224 MM) to be funded by shareholders.

PSEP Rate Impacts

Illustrative Class Average End-User Rates
($ per Therm)

	Rates Effective June 1, 2011			
	Present June 2011 Rates	Gas Pipeline Safety Rate	Total Rate Including Gas Pipeline Safety Rate	Percent
CORE RETAIL - Bundled				
Residential Non-CARE	$1.223	$.052	$1.275	4.3%
Small Commercial Non-CARE	$.975	$.052	$1.027	5.3%
Large Commercial	$.766	$.052	$.818	6.8%
NGV1 - (uncompressed service)	$.661	$.052	$.713	7.9%
NGV2 - (compressed service)	$1.912	$.052	$1.965	2.7%
CORE RETAIL - Transport Only				
Residential Non-CARE	$.650	$.052	$.702	8.0%
Small Commercial Non-CARE	$.418	$.052	$.470	12.5%
Large Commercial	$.248	$.052	$.300	21.0%
NONCORE - Transportation Only*				
Industrial - Distribution	$.171	$.025	$.196	14.6%
Industrial - Transmission	$.069	$.025	$.094	36.0%
Industrial - Backbone	$.042	$.002	$.044	5.0%
Electric Generation - Transmission (G-EG-D/LT)	$.029	$.025	$.054	86.0%
Electric Generation - Backbone (G-EG-BB)	$.007	$.002	$.010	28.6%
NGV 4 - Distribution (uncompressed service)	$.155	$.025	$.180	16.1%
NGV 4 - Transmission (uncompressed service)	$.055	$.025	$.080	45.2%
WHOLESALE CORE AND NONCORE (G-WSL)*				
Alpine Natural Gas	$.026	$.025	$.051	97.1%
Coalinga	$.026	$.025	$.051	96.9%
Island Energy	$.027	$.025	$.052	90.9%
Palo Alto	$.025	$.025	$.050	98.5%
West Coast Gas - Castle	$.100	$.025	$.125	24.8%
West Coast Gas - Mather Distribution	$.123	$.025	$.148	20.2%
West Coast Gas - Mather Transmission	$.026	$.025	$.051	96.0%

* Noncore end-use rate increases range from 3.5%-5% on total bill, assuming cost of commodity equal to PG&E's core large commercial commodity rates.

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505 Van Ness Ave., San Francisco

FOR IMMEDIATE RELEASE **PRESS RELEASE**

Media Contact: Terrie Prosper, 415.703.1366, news@cpuc.ca.gov Docket #: R.11-02-019

CPUC APPROVES PIPELINE SAFETY PLAN FOR PG&E; INCREASES WHISTLEBLOWER PROTECTIONS

SAN FRANCISCO, December 20, 2012 - The California Public Utilities Commission (CPUC) today approved Pacific Gas and Electric Company's 2012-2014 Pipeline Safety Implementation Plan. The CPUC required PG&E to pressure test 783 miles of natural gas pipeline, replace 186 miles of pipeline, upgrade 199 miles of pipeline to allow in-line inspection, and install 228 automated shut off valves.

The CPUC authorized rate recovery for 39 percent of the funds PG&E requested, approving $299 million in increased revenue for the 3-year period. PG&E's rate for residential core service will increase by about 1.5 percent as a result of today's decision. The CPUC required that PG&E's SHAREHOLDERS BEAR THE RISK OF COST OVERRUNS BECAUSE PG&E'S PAST MANAGEMENT DECISIONS Led to the need to undertake this massive project on an expedited schedule.

Additionally, PG&E shareholders will bear the costs of pressure testing pipeline for which pressure test records are missing. PG&E is required to continue its record management improvement project; however, due to past deficiencies in document management, the costs of this project and its computer database may not be recovered from ratepayers.

The CPUC also required PG&E to scrutinize and evaluate its internal corporate operations as well as external events, such as trenching work by other entities, to capture cost-effective safety improvement opportunities.

"TODAY'S DECISION PLACES PG&E FIRMLY ON THE PATH TOWARD A MUCH SAFER NATURAL GAS TRANSMISSion system, while limiting the cost to ratepayers to those expenditures that are truly needed to meet the higher safety standards that the CPUC has adopted. All costs that are the result of past PG&E MISTAKES ARE ASSIGNED TO THE COMPANY'S SHAREHOLDERS," SAID CPUC COMMISSIONER MIKE Florio.

SAID COMMISSIONER CATHERINE J.K. SANDOVAL, "I support an ongoing and unwavering commitment to safe gas transmission and distribution systems and operations for now and future decades."

ADDED COMMISSIONER MARK J. FERRON, "AS A RESULT OF APPROVING THESE NEW SAFETY PLANS, THE UTILITIEs will need to raise substantial amounts of capital to implement this new standard. Today's decision strikes the right balance between the share of costs borne by PG&E shareholders and those borne by RATEPAYERS."

Separately, the CPUC today adopted new protections for safety whistleblowers, in accordance with Assembly Bill 705. The new protections ensure that all natural gas utilities in the state post in a prominent physical location, as well as in electronic form on their website where employees are likely to see it, information about whistleblower protections, including the CPUC's Whistleblower Hotline (800- 649-7570, fraudhotline@cpuc.ca.gov).

The proposals voted on today are available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K622/40622382.PDF and http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M037/K661/37661696.PDF.

For more information on the CPUC, please visit www.cpuc.ca.gov.

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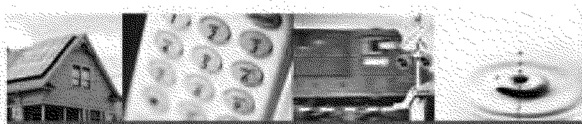
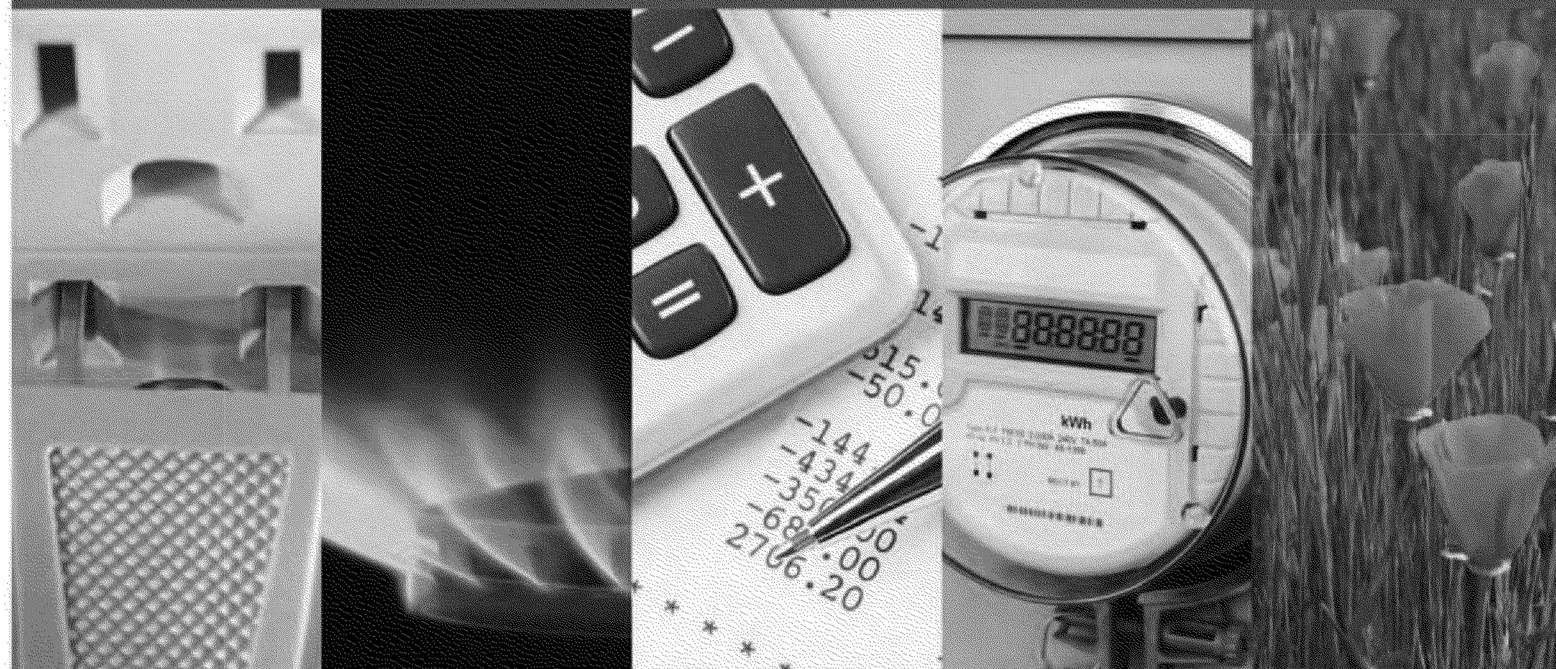


California Public Utilities Commission

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



May 2010

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I. Introduction

On October 11, 2009 Governor Schwarzenegger signed Senate Bill 695. Among other things, SB 695 added Section 748 to the Public Utilities Code:

> 748. (a) The commission, by May 1, 2010, and by each May 1 thereafter, shall prepare and submit a written report, separate from and in addition to the report required by Section 747, to the Governor and Legislature that contains the commission's recommendations for actions that can be undertaken during the succeeding 12 months to limit utility cost and rate increases, consistent with the state's energy and environmental goals, including goals for reducing emissions of greenhouse gases.
>
> (b) In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases.
>
> (c) The commission shall post the report required by subdivision (a) in a conspicuous area of its Internet Web site.

This report is submitted by the Public Utilities Commission in compliance with Section 748.

II. CPUC Actions to Limit Utility Cost and Rate Increases

The CPUC regulates investor-owned electric and natural gas utilities within the State of California, including Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), San Diego Gas and Electric Company (SDG&E), and Southern California Gas (SoCalGas). Collectively, these utilities serve over two-thirds of total electricity demand and over three-quarters of natural gas demand throughout California.[1] Through its oversight of these utilities, the CPUC develops and administers energy policy and programs to serve the public interest, and ensures compliance with statutory mandates and CPUC decisions, resulting in reliable, safe and environmentally sound energy services at lowest reasonable rates for the people of California.

The Commission's regulatory process is governed by the Public Utilities Code and by the Commission's Rules of Practice and Procedure, with each formal proceeding conducted by the Commission following due process affording various parties the opportunity to present their position and recommendations in prepared written and oral testimony before the Commission. Evidentiary hearings are held when warranted and a proposed decision is prepared by the presiding officer (an administrative law judge or an assigned commissioner, depending on the categorization of a proceeding) for a vote by the Commission. Given this statutory regulatory process, the Commission must be careful not to prejudge issues in any pending proceedings and make specific recommendations about likely outcomes of individual cases.

The CPUC's cost-setting and ratemaking proceedings over the next 12 months will continue to be consistent with the Energy Action Plan (EAP) II, adopted by the CPUC and California Energy Commission in 2005, and updated in February 2008. The Energy Action Plan established a "loading order," or priority sequence for actions to address California's increasing energy needs. The EAP's loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs, followed by renewable resources and distributed generation, and to the extent that these resources are inadequate, clean and efficient fossil-fired electric generation.

The EAP identifies six sets of actions of critical importance which are listed below. The CPUC is at the helm of many of these action areas, as will be described later in each section on specific programs being implemented by the CPUC.

- Optimize Energy Conservation and Resource Efficiency
- Accelerate the State's Goal for Renewable Generation
- Ensure Reliable, Affordable Electricity Generation
- Upgrade and Expand the Electricity Transmission and Distribution Infrastructure
- Promote Customer and Utility Owned Distributed Generation

[1] In addition to the four large utilities, the CPUC also regulates a number of small and multi-jurisdictional energy utilities; these utilities are not subject to the reporting requirements of Section 748.

- Ensure Reliable Supply of Reasonably Priced Natural Gas

This report focuses on a description of pending proceedings that are under consideration before the Commission, as well as some annually recurring rate applications that are likely to be filed later in the year. The report provides dollar amounts requested by the utilities in the pending cases along with a summary of the reasons for the requested amounts. This should give the legislature a sense of the magnitude of the requests by the utilities that this Commission will be evaluating within the next 12 months. In addition, this report provides a description of various program areas that contribute to utility costs, along with any actions that the Commission is considering to continually improve the efficacy of those program areas.

The following is a list of some actions that the Commission will be taking in the next 12 months to ensure that the costs and rates authorized by the Commission are reasonable and the many statutorily mandated programs and public policy initiatives that the Commission is entrusted to administer are implemented efficiently.

Electricity

- The Commission conducts an in-depth review of all infrastructure-related investments and operations and maintenance (O&M) costs related to utility owned generation and distribution in each utility's general rate case (GRC). The Commission is currently reviewing PG&E's test year 2011 GRC. Typically, the review results in a scaling back of the utilities' total requested GRC revenue requirement. The Commission will diligently review PG&E's 2011 GRC revenue requirement request along with the input from a large number of interveners that will provide testimony and recommendations in the case.

- The Commission will scrutinize the utilities' power purchase and fuel cost recovery requests in the Energy Resource Recovery Account (ERRA) proceedings and provide for refunds for customers when the ERRA triggers warrant.

- Listed first in the State's Energy Action Plan (EAP) loading order, energy efficiency is the least cost, most reliable, and most environmentally sensitive resource available to meet growing demands for energy in California. The Commission is continually looking for improvements in the evaluation, measurement and verification (EM&V) studies to ensure the programs achieve maximum cost-effectiveness and the goals of the programs are met. Beginning with the 2006-2008 program cycle, the Commission also adopted a Risk/Reward Incentive Mechanism (RRIM), which was intended to reward IOUs for the successful procurement of cost-effective energy efficiency programs. In the next 12 months, the Commission will consider improvements to the RRIM framework in Rulemaking 09-01-019.

- The Commission will be considering a number of measures and protocols to ensure the cost-effectiveness of demand response programs and to better enable customers to reduce demand in response to price signals through dynamic rates.

- The Commission will be considering a number of enhancements to the low income programs, such as outreach to customers with high energy use and to increase the over-all cost-effectiveness of the program. The Commission will be monitoring and evaluating the many pilot programs and studies it has authorized with the intent to use the results to further improve program delivery, customer marketing and outreach efforts, program efficiencies and cost effectiveness all while maximizing customer benefits.

Natural Gas

- In the coming year, the Commission expects to maintain natural gas utility rates at reasonable levels in the following manner:
    - provide incentives to utilities to keep natural gas procurement costs low
    - allow expeditious approval of a diverse and reasonably-priced portfolio of interstate pipeline capacity
    - provide core customers with adequate amounts of natural gas storage capacity, and
    - allow utilities to engage in efficient natural gas hedging practices.

- The Commission will scrutinize natural gas utility operational costs and rates for transmission, distribution and storage in several major proceedings, including the PG&E 2011 General Rate Case (GRC), the PG&E Gas Transmission and Storage proceeding, and the SoCalGas/SDG&E 2012 GRC.

- The CPUC will ensure that public purpose programs are conducted efficiently and provide the maximum benefits for which they are intended. The CPUC will also be reviewing and approving the budget for the natural gas research and development program that was entrusted by the CPUC to the California Energy Commission (CEC) to administer.

Utilities' Recommendations to Limit Cost and Rate Increases

Pursuant to Section 748(b), the four major electric and gas companies submitted their reports to the Energy Division on various components of costs and their recommendations to limit costs and rate increases.

Reports provided by the utilities in response to the requirements of 748(b) are attached as an Appendix to this report.

III. Electric Utility Revenue Requirements

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

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

In recent years, transmission-related revenue requirement and rate increases have largely been due to capital additions, O&M and lesser amounts of A&G, and special FERC incentives.

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

General Rate Cases

Approximately 45% of the utilities' revenue requirements are set in general rate cases at the CPUC and at FERC. The transmission revenue requirement is determined by the Federal Energy Regulatory Commission (FERC) in transmission owner rate cases following similar test year rate making.

The major components of costs that are reviewed and determined in the GRCs include the following major elements:

2009 General Rate Case Revenue Requirements (000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,827,122	$1,853,119	$445,646
Depreciation	$1,019,254	$1,106,992	$285,756
Return on Rate Base	$909,993	$1,066,918	$246,799
Taxes	$617,138	$819,612	$176,474
Total	**$4,373,507**	**$4,846,641**	**$1,154,675**

In December 2009, PG&E filed its test year 2011 GRC application which will be reviewed by the Commission in 2010. The Commission will carefully consider PG&E's request and other parties' testimony in the case, and decide what level of revenues PG&E will need to recover from customers to provide safe and reliable service at just and reasonable rates. SDG&E, SoCalGas, and SCE are currently scheduled to file test year 2012 GRC applications in late 2010. The Commission will address similar issues in 2011 after SCE, SDG&E, and SoCalGas file their test year 2012 GRC applications.

Electric Fuel and Purchased Power

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

Annual Fuel and Purchased Power Cost Forecasts Included in Commission Authorized Electric Rates ($ million)

PG&E: Effective January 2010 (D.09-12-021)	**SCE**: Effective March 2010 (D.10-02-019)	**SDG&E**: Effective May 2009 (D.09-04-021)
$3,732	$3,310	$875

Utilities' actual fuel and purchased power costs, and the revenues they collect from customers to pay these costs, are tracked in a balancing account with interest. The account balance (difference between costs and revenues) is returned to customers if revenues exceed costs, or recovered from customers if costs exceed revenues, in a subsequent ERRA or other Commission proceeding.

The costs shown above do not include ERRA account balances that are returned to or recovered from customers.

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

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

Rate Related Proceedings in the Next 12 Months

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

Most of these are utility specific rate filings. However, two -Wildfire Insurance Costs and Economic Development Rate proceedings -are joint proceedings involving all the four major energy utilities.

Wildfire Insurance Costs

In August 2009, PG&E, SDG&E, SoCalGas, and SCE jointly filed an application requesting to establish balancing accounts to recover from ratepayers costs paid by the utility arising from wildfires. These costs include payments to third parties for damage or loss claims associated with wildfires, outside legal expenses associated with any third-party claims, payments to government authorities for fire suppression costs and environmental damage, and changes in wildfire premium amounts from the amount assumed in the last GRC. The utilities supported their request by citing significant increases in wildfire insurance premiums. For example SDG&E and SoCalGas's annual insurance premium that expired in June 2009 was $13.6 million; it had a liability limit of $1.2 billion, and a $1 million deductible. Their current annual premium is $55.2 million with a general liability limit of $800 million and a wildfire liability limit of $399 million, and a $35 million deductible for wildfires.

The Commission will consider the utilities' proposal in 2010. The Assigned Commissioner and ALJ issued a ruling in late 2009 in this case which expressed concerns about the utilities' proposal. The ruling notes that the utilities' proposal would provide no financial motivation to defend wildfire claims and that ratepayers would bear the cost of the claims with no practical means of defending the claims. The ruling directs parties to confer on alterative approaches with the goals of developing proposals that reduce risk and limit revenue requirements.

Economic Development Rates

In 2005, the Commission approved an electric economic development rate (EDR) program for large commercial and industrial customers of SCE and PG&E. The program provided discounted rates to customers to attract businesses to locate in California or expand their operations in the State, and to retain businesses which would otherwise close or leave the State. The program was originally scheduled to terminate at the end of 2009, but the sunset date was postponed while the Commission reviews PG&E's and SCE's applications to extend the program through 2012. The program has a limit of 100 MW of total load eligible to participate for each utility. SCE currently has 47.5 MW of load enrolled in the program and PG&E has 88.3 MW of load enrolled. In their applications to extend the program, SCE requested to increase the eligible limit to 250 MW and PG&E proposes to increase the limit to 200 MW.

The EDR programs can potentially benefit ratepayers by increasing revenues available to contribute to the utilities' fixed costs of doing business and thus lower rates to other customers. The Commission is expected to issue a decision on PG&E's and SCE's applications to extend the EDR program by the end of 2010.

SCE Rate Requests

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

- **2008 ERRA Compliance A.09-04-002:** In this application, the Commission is reviewing SCE's procurement activities during 2008 to ensure that the procurement costs recorded in 2008 are in compliance with SCE's adopted procurement plan. The Commission is also reviewing various balancing and memorandum accounts, including the ERRA, to ensure that the recorded entries are appropriate and are in compliance with Commission decisions and tariffs.

  Requested Increase: $35.8 million which is associated with recovering costs recorded in four memorandum accounts.

- **2009 ERRA Compliance A.10-04-002:** In this application, the Commission is reviewing SCE's procurement activities during 2009 to ensure that the procurement costs recorded in 2009 are in compliance with SCE's adopted procurement plan. The Commission is also reviewing various balancing and memorandum accounts, including the ERRA, to ensure that the recorded entries are appropriate and are in compliance with Commission decisions and tariffs.

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

- **CEMA Bark Beetle A.09-11-011***:* SCE has requested to recover O&M costs recorded in the Catastrophic Event Memorandum Account (CEMA) associated with mitigating the unprecedented fire hazard caused by the bark beetle infestation during 2007 and 2008.

Requested Increase: $16.6 million

- **CEMA Wind and Firestorm A.10-04-026:** SCE has requested to recover incremental O&M and capital revenue requirement associated with the 2007 wind and firestorms.

  Requested Increase: $10.6 million

- **Nuclear Decommissioning Cost Triennial Proceeding A.09-04-009*:*** In this application SCE has requested a decrease in the annual nuclear decommissioning trust funding requirements and addresses other related decommissioning issues.

  Requested decrease: ($22.6) million

SCE Rate Related Requests expected later this year

- **2011 ERRA Forecast A.10-07-XXX***:* In this application which will be filed on July 30, 2010, the Commission will authorize the fuel and purchased power revenue requirement to be included in 2011 rate levels.

  Requested Increase: Not known at this time. Depends on the fuel price forecast and purchased power costs. The ERRA-related revenue requirement approved in SCE's last ERRA decision (D. 10-02-019) and embedded in current rates is $3.31 billion.

- **2009 GRC Post Test Year: Request to Implement already authorized GRC increase:** In D.09-03-025, the Commission authorized SCE to increase its 2009 authorized GRC revenue requirement of $4.830 billion by 4.25% in 2010, and an additional 4.35% in 2011. The increase will be implemented on January 1, 2011 through an advice letter that will be filed on November 1, 2010.

  Requested increase: $219 million

- **DWR Revenue Requirement**: In this proceeding, the Commission will authorize the 2011 DWR Power and Bond Charges. It is expected that there will be an increase in SCE's DWR Power Charge due to the removal of the "transfer payment" from the other IOUs that is currently reflected in SCE's 2009 Power Charge revenue requirement. The removal of the transfer payment could result in an increase of approximately $500 million to SCE's customers assuming no other change in DWR's revenue requirements. This increase could partially be offset by the termination of DWR contracts allocated to SCE, as well as the refund of any DWR over-collections and operating reserve. DWR's revenue requirements currently account for 11.3% of SCE's total system revenue requirement.

  Requested Increase: Not known yet

- **SONGS 2&3 Steam Generator Replacement**: The Commission has authorized SCE (D.05-12-040) to put in rates the revenue requirement associated with replacing the steam generators for both SONGS 2&3 on January 1st after the units return to commercial operation. The generators for Unit 2 have been replaced and the unit is back in service. SCE expects the generators for Unit 3 will be replaced and the unit will return to commercial operation by December 31, 2010. SCE is expected to include the associated revenue requirement with the replacement of the steam generators in both units in rates on January 1, 2011.

Requested Increase: Not known yet

PG&E Rate Requests

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

- **Distribution Reliability (Cornerstone) Update - A.08-05-023:** PG&E requested $2.051 billion in capital additions to improve electric distribution reliability Electric Base/ Distribution.

  Requested Recovery: $41 million

- **Fuel Cell Project - A.09-02-013:** D.10-04-028 authorized up to $20.3 million of capital costs for utility ownership of 3 MW of fuel cell facilities.

  Requested Recovery: $8 million

- **Photovoltaic Program - A.09-02-019:** D.10-04-052 authorized up to $1.45 billion of capital costs for 250 MW of utility owned solar PV projects. The decision also authorized PG&E to enter into Power Purchase Agreements for an additional 250 MW of solar PV projects to be owned and operated by independent power producers.

  Requested 2011 Recovery: $3 million

- **2010-2012 Nuclear Decommissioning A.09-04-007:** Triennial request for approval of updated nuclear decommissioning revenue requirements. Partial settlement agreement filed for ~$25M per year revenue requirement. Total cost in 2008 dollars for HBPP & DCPP: $2.34B

  Requested Recovery: $50 million

- **SmartAC 2009 Update A. 09-08-018:** PG&E requested authorization to update 2010-2011 SmartAC program and related budget of $123 million.

  Requested Recovery: $32 million

- **2008 Long-term RFO - A. 09-09-021:** Requests approval of $1,168 million of capital costs for a 580 MW purchase and sale agreement (Oakley Power Generating Facility) that is scheduled to go online in mid-2014. The procurement costs associated with the remaining power purchase agreements (Mirant Marsh Landing and Midway Sunset) under this same LTRFO application will flow through ERRA upon CPUC approval or plant operational.

  Requested Recovery: None in 2011

- **Smart Grid Compressed Air Energy Storage (CAES) Project - A.09-09-019**: D.10-01-025 authorized $24.9 million of costs to fund the design and feasibility studies for a 300 MW compressed air energy storage demonstration project.

  Requested recovery: $18 million

- **Manzana Wind Project - A.09-12-002:** Requests approval of $911 million of capital costs for a 246 MW wind project.

  Requested Recovery: None in 2011

- **PG&E 2011 General Rate Case A.09-12-020:** PG&E requests a revenue requirement of $5.391 billion effective January 1, 2011 in its gas and electric distribution and generation base revenue requirement as compared to 2011 projected revenue requirement. The request amounts to an increase of 19.7% for gas distribution, 17.3% for electric distribution and 19% for electric generation over 2011 projected revenue requirements. PG&E requests this increase in revenue requirement for activities such as maintaining and upgrading its electric and gas distribution systems, enhancing its customer support and energy supply functions, and maintaining a qualified workforce.

  Requested Increase: $1.048 billion

- **Rate Design Window 2010 -Peak Time Rebate A. 10-02-028:** PG&E requests approval for Peak Time Rebate (PTR) program that provides incentives for customers to respond to price signals on event days when demand is expected to be high.

  Requested Increase: $33 million

- **Diablo Canyon Power Plant Seismic Survey (3D) A.10-01-014:** PG&E requests to recover costs associated with performing additional seismic studies at and around Diablo Canyon Power Plant (DCPP) as recommended by the California Energy Commission in their Commission Report, "An Assessment of California's Nuclear Power Plants: AB 1632 Report"

  Requested Increase: $17 million

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

  Requested Increase: $85 million

- **ERRA 2009 Compliance Filing A.10-02- 012:** Recovery of costs related to the Market Redesign and Technology Upgrade (MRTU) initiatives.

  Requested Increase: $60 million out of which $18 million is for recovery in 2011.

- **Accelerate Generator Settlement Refunds (1)- Advice 3625-E:** Request to reduce bundled average electric rate by 3% as part of summer rate relief.
  Requested Decrease: $121 million

- **Accelerate TO11 Refunds (1) Advice 3633-A:** Request to reduce bundled average electric rate by 3% as part of summer rate relief
  Requested decrease: $121 Million

- **CSI rate suspension D.10-04-017*:*** PG&E filed a Petition to Modify D. 08-12-004 requesting a temporary suspension in CSI collections which the Commission approved on April 8th
  Requested decrease: $106 million

- **General Rate Case (GRC) 2011 Phase II - Dynamic Pricing A.10-03-014:** The request includes $7 million in revenue requirements for new voluntary Real Time Pricing rate options available May 1, 2012, and $6 million in revenue requirements for a new Revised Customer Energy Statement
  Requested Increase: $53 million

- **TO 12 (TY 2010) Settlement ER09-1521-000:** Annual transmission settlement with FERC
  Requested decrease: $73 million

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

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

- Energy Resource Recovery Account (ERRA) 2011 Forecast
- Annual Electric True-Up (AET) 2011
- DWR 2011 Revenue Requirement Forecast Filing
- Default Residential Rate Programs
- FERC TRBA/ECRA/RSBA Filing
- Public Purpose Program Surcharge Gas Rate Filing 2010 - Advice Letter
- SB 695 Res Rate Change (T1 & T2) Advice Letter
- Energy Resource Recovery Account (ERRA) 2010 Forecast – Update
- Annual Electric True-Up (AET) 2011 - Advice Letter Update
- FERC TACBA Filing

SDG&E Rate Requests

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

- **CEMA Application-2007 Wildfires filed March 2009:** SDG&E is requesting recovery for incremental expenses and capital related costs incurred to restore service or repair facilities as a result of damages caused by the 2007 Wildfires.
  Requested Increase: Approx $ 32 million.

- **Nuclear decommissioning triennial application filed April 2009:** To update contribution amounts made to nuclear decommissioning trust funds for San Onofre Nuclear Generating Station Units # 2 and 3.
  Requested Increase: Approx. $5.8 million.

- **Z- Factor Application-Insurance Premiums filed August 2009:** SDG&E is seeking recovery for unforeseen costs related to increases in liability insurance policy premiums through the Z-factor mechanism.
  Requested Increase: Approx. $28.9 million

- **2010 ERRA Forecast Application filed October 2009:** Recovery of SDG&E's energy procurement costs including expenses associated with fuel and purchased power, utility retained generation, CAISO related costs and costs associated with net short procurement requirements to serve SDG&E's bundled customers.
  Requested decrease: Approx. $44 million

- **2010 ERRA Trigger Application filed in April 2010:** SDG&E is seeking approval to return over-collected balance.
  Requested Decrease: Approx. $75 million.

SDG&E rate related requests expected later this year:

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

- 2011 DWR Implementation Advice letter to be filed in Nov/Dec 2010
- Non-fuel generation balancing account update: November 2010
- FERC Transmission Owner 3 true-up filing: August 2010
- Electric Public Purpose Program Update Advice letter: October 2010
- Electric Regulatory Account Update Advice letter: October 2010
- SB 695 Residential rate change: November 2010
- Electric Consolidated Advice letter: December 2010

IV. Program Specific Proceedings and Activities

The Commission implements a wide array of energy policies in accordance with the Energy Action Plan (EAP) and as mandated by various statutes and state's energy policy initiatives. The Commission continually strives to improve the efficacy of these programs by making sure the programs are cost-effective and are managed efficiently by the utilities. In some cases the programs may not be as cost-effective in the short run but are justified by their cost-effectiveness over the long run as the programs spur market development and innovation which can bring down costs over time.

Long Term Procurement and Resource Adequacy

The CPUC adopted a System and Local Resource Adequacy (RA) policy framework (PU Code Section 380) in 2004 in order to ensure the reliability of electric service in California. R.09-10-032 is the most recent CPUC proceeding to refine the RA program. In addition, the CPUC administers a Long Term Procurement Proceeding (LTPP) which implements AB 57 (PU Code Section 454.5), passed in 2002. Every two years, the CPUC holds a Long Term Procurement Plan (LTPP) proceeding to evaluate the system's need for new conventional resources and to serve as the "umbrella" proceeding to consider, in an integrated fashion, all of the Commission's EAP loading order resource policies and programs.

A major element that drives costs of the RA program is renewables integration. Wind and solar resources only produce electricity when the sun shines or the wind blows. Therefore, it is difficult to accurately predict the amount of energy that will be delivered by intermittent resources during times of peak demand. Therefore, other generation needs to be procured in order to ensure reliability if intermittent resources are not available. Some generation is procured in order to be ready if intermittent resource can not produce. Customers pay for these resources even if they only operate a limited amount of time.

Procurement of capacity and energy is currently accomplished mostly through direct contracting between the load serving entities (LSEs) and generators (bilateral contracting). LSEs then bid resources into the CAISO markets. There is significant variation in contract prices. This variation between contract prices results from different energy and capacity value depending on location, ability to respond quickly to system needs, vintage of plant, and market competitiveness. There are also many longer term contracts, such as DWR contracts, that contribute to overall rate payer costs.

Several proceedings within the next 12 months in this program area have the potential to affect ratepayer costs, either by raising or lowering the required level of reserves, or by authorizing new generation to meet system reliability requirements. There are also continuing policy developments such as State Water Resource Control Board regulations related to the use of Once Through Cooling, and the gradual expiration of Department of Water Resources energy contracts that may have rate impacts within the next 12 months. CPUC staff expects the combined effects of Long Term Procurement and RA policies as well as other changes to California's energy market to lead to higher rates within the next 12 months, and continue to raise rates in the 12 months thereafter. These rate increases will however prevent further costs later, as aging infrastructure is replaced with new, more effective and less polluting electricity infrastructure.

Proceedings in next 12 months that will impact revenue requirements or rates

Current proceedings at the CPUC may have rate impacts both positive and negative in the near term. Although the RA and LTPP programs have the effect of stabilizing and hedging energy prices by requiring sufficient capacity construction and bilateral contracts for that capacity, it is difficult to quantify the overall rate impacts of these hedges. These programs hedge against the danger of added emergency costs related to lost productivity during system emergencies and emergency resource procurement. Specific proceedings and other processes that may have positive or negative rate impacts within the next 12 calendar months are listed below.

- Current LTPP and RA market structure (R.05-12-013)
- Study and determination of the appropriate Planning Reserve Margin (R.08-04-012)
- Construction of New Generation via the LTPP program (R.08-02-007)
- Impacts of Once Through Cooling regulations promulgated by the SWRCB
- Impacts of expiring DWR contracts and reduced reliability must run contracting since the Energy Crisis

Long Term Procurement and RA market structure

The CPUC ensures that the IOUs have adequate capacity and energy to serve their customers' electricity needs reliably and at reasonable cost. The CPUC analyzes IOU plans for developing preferred resources, evaluates current resources and the prospect of retirements and compares the overall supply to the CEC's forecast of needs over the next ten years. If need exceeds forecast supply and preferred resources can not meet the requirements, the CPUC authorizes the IOUs to hold an auction for the right to build new generation. IOUs develop projects that benefit the entire CAISO controlled system, including ESPs and CCAs. Because contracting authority is based on forecasts of need, retirements, and construction schedules, at any specific time the amount of infrastructure may exceed current demand, but is needed to allow the retirement of generators that may be inefficient and/or environmentally harmful.

Study and determination of the appropriate Planning Reserve Margin (PRM)

In 2003, the CPUC adopted a PRM of 15-17 %. This is the amount of resources in addition to resources directly serving peak load that LSEs are required to maintain in order to protect the system from generator failures, inaccurate load forecasts and other contingencies. The CPUC is currently evaluating the most efficient level of the PRM in R.08-04-012. Generally, lowering the reliability standard of the system will lower costs and increase the chance of an outage while raising the PRM will increase costs and reduce the chance of firm load drop. Analytical studies aimed at determining precise values of customer risk tolerance and risk preferences relative to economic costs of service interruption have not yet been undertaken. A study of this sort would provide a more analytical means by which the CPUC could calibrate the amount of reliability provided by CPUC policies, and the amount of reserves that LSEs are required to carry. An example of customer tolerance for service interruption is Demand Response (DR) programs, where certain customers are willing to trade service interruption for an incentive payment.

Construction of New Generation via the LTPP program

The LTPP program requires IOUs to assume the task of constructing conventional thermal generation apart from their other procurement activities (RPS, DR, and EE) to meet projected infrastructure needs in their service territories. Added costs for the construction of these new resources are reasonable, given the approval of procurement policies and authorized amounts in CPUC LTPP decisions. The most recent LTPP decision (D.07-12-052) authorized 2,130 to 3,430 MW of new generation to be constructed to support system reliability needs going out to 2018. These new resources will be more expensive than continued operation of existing resources, but will be more efficient and more environmentally friendly.

The CPUC authorized this new procurement amount partially due to the possibility that the benefits from retiring older less efficient plants (cleaner air, less fuel use, less water use) would outweigh the costs of new construction from a policy perspective. Without procurement designed to offset retiring generation, there would be no need for new construction however. California has made this a policy preference, and done so by enacting AB 32 designed to, among other things, decrease GHG emissions from the electricity generation sector. Future procurement decisions may authorize additional procurement for the IOUs to perform related to renewable integration, failure of contracted generation to perform or come online as planned, or for other reasons.

Impacts of Once Through Cooling mitigation regulations promulgated by SWRCB

Currently the State Water Resources Control Board (SWRCB) is considering adoption of rules to phase out the use of Once Through cooling (OTC) at existing generating plants. These existing plants comprise over 30% of the total generating capacity within the state of California. The plants are concentrated in the Los Angeles Basin, the Greater Bay Area, and San Diego and many are currently needed to ensure reliability in those areas. The majority of the plants that use OTC are in Southern California, and present unique problems of jurisdiction, air quality restrictions, and coordinated planning.

OTC mitigation, particularly in the Los Angeles Basin, is likely to be quite expensive. Mitigation will be done via a variety of approaches, such as transmission improvements, construction of new plants, replacing the cooling systems on existing plants, increased distributed generation, and demand side alternatives (e.g. energy efficiency and demand response), but there will be rate impacts of this OTC policy, as mitigation activities require large infrastructure investments.

Impacts of expiring DWR contracts and reduced CAISO reliability backstop contracting since Energy Crisis

Since the advent of the RA program, there has been a significant decrease in the amount of CAISO reliability backstop contracts executed by the CAISO. From a high of over 10,000 MW of capacity in 2005 to a low of around 1,000 MW for 2010, this decrease in MW has represented a decrease in the CAISO's portfolio and financial commitment. It is uncertain whether overall the rate impacts of decreased CAISO reliability backstop contracts are offset by an increase in costs relative to LSE contracts with those particular units. Several former CAISO reliability backstop contracts units are also impacted by the SWRCB rules governing OTC, so the situation with these units is likely to be complicated.

During the Energy Crisis, DWR entered into energy contracts to ensure electric reliability. Since the signing of these contracts, changes in the market have made these contracts somewhat incompatible with current grid operations. Ratepayers have incurred costs to account for these incompatible contract terms, such as increased CAISO backstop contracting. Over the next 12 months, several DWR contracts will expire, reducing these costs.

Energy Efficiency

In January 2005,[2] the CPUC adopted an administrative structure for post-2005 energy efficiency programs designed to meet the objectives of the Energy Action Plan, the load reduction reflected in the energy savings goals adopted in September 2004, and the importance of energy efficiency as the priority resource to meet California's energy needs in the future.[3] The Commission replaced the design of previous program cycles, which occurred either annually or, in the case of the 2004-2005 cycle, over the course of two years, with a three-year program cycle to encourage longer term planning. The Commission directed that utility energy efficiency performance be evaluated based on overall portfolio energy savings achievements, rather than on the performance of each individual program, in order to "encourage innovation, and allow for some risk-taking on pilot programs and/or measures in the portfolio."[4] Listed first in the loading order, energy efficiency is the least cost, most reliable, and most environmentally sensitive resource available to meet growing demands for energy in California.

For the 2006-2008 and future program cycles, the adopted structure returned to the utilities the functions of selecting the activities and implementers for the portfolio of energy efficiency programs and the daily tasks associated with administering and coordinating program activities during funding cycles. The CPUC Energy Division became responsible for program oversight as well as managing and contracting for all evaluation, measurement and verification (EM&V) studies to:

- Measure and verify energy and peak load savings for individual programs, groups of programs and at the portfolio level;
- Generate the data for savings estimates and cost-effectiveness inputs;
- Measure and evaluate achievements of energy efficiency programs, groups of programs and/or the portfolio terms of the "performance basis" established under the CPUC-adopted EM&V protocols;[5]
- Evaluate whether programs or portfolio goals are met.

[2] D.05-01-055, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/43628.PDF
[3] D.04-09-060, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/40212.PDF
[4] D.05-04-051, available at: http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/45783.PDF.
[5] The California Energy Efficiency Evaluation Protocols are guidance tools policymakers use to plan and structure evaluation efforts and that staff of the California Public Utilities Commission's Energy Division (CPUC-ED) and the California Energy Commission (CEC) (collectively the Joint Staff), and the portfolio (or program) administrators (Administrators) use to plan and oversee the completion of evaluation efforts. The Protocols are also guidance documents for the design and evaluation of programs implemented after December 31, 2005. The Protocols are available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/

Evaluation

The data representing the actual energy efficiency savings generated by the IOU programs undergo a process of refinement over the course of each program cycle. Initially, the IOUs file their proposed portfolio of programs and project the savings achievable from each program and for the entire portfolio. Typically this indicates that their program offerings will exceed the annual and cumulative CPUC goals set for that program cycle.

Once approved, programs begin operation, achieve actual savings and the IOUs report these savings to the CPUC/EEGA website monthly, quarterly and annually until the completion of the program cycle. The reported figures are referred to as "*ex-ante*" because they use some savings assumptions for the purposes of reporting and projected energy savings. Over the course of a program cycle, these *ex-ante* figures may be updated and used to determine verified energy savings results.

The CPUC requires rigorous measurement and verification of the reported savings and evaluation of the largest programs by independent contractors. This process allows for actual savings to be determined for certain measures and verifies that savings that were reported were actually installed. This "true-up" process adjusts the savings achievements reported by IOUs and results in the "*ex-post*" (actual post-installation) energy savings totals.

In early 2009, the CPUC Energy Division issued the "Energy Efficiency 2006-2007 Verification Report", which analyzed the IOU-reported energy savings for the two-year 2004-2005 program cycle and the first two years of the 2006-2008 program cycle. The Verification Report analyzed IOU reported energy savings using actual energy efficiency measure installations and various parameter values used to calculate energy savings from the IOUs' program portfolios.

Cost-Effectiveness

The IOUs also estimate the cost-effectiveness of their respective portfolios/programs, as measured by the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests. The TRC measures the net resource benefits from the perspective of all ratepayers by combining the net benefits of the program to participants and non-participants. Benefits are the costs of supply-side resources avoided or deferred, while the costs include all those paid by both the utility and participant and encompass costs of the measures and installed equipment and the costs incurred to start and administer the program. Under the PAC, program benefits are the same as those related to determining the TRC, but costs include all costs incurred by the program administrator, including all incentives and all other program costs. Cost-effectiveness is achieved when the value of energy savings (in dollars) is greater than the cost of utility financial incentives to customers and all other program costs. A TRC or PAC ratio that is larger than "1" means that the benefits of a program exceed the costs of that program.

The Risk-Reward Incentive Mechanism (RRIM)

Beginning with the 2006-2008 program cycle, the Commission also adopted a Risk/Reward Incentive Mechanism (RRIM), which was intended to reward IOUs for the successful procurement of cost-effective energy efficiency programs and address an inherent utility bias towards supply-side procurement under cost-of-service regulation and investment in "steel in the ground" as a means of generating earnings for shareholders.

The RRIM seeks to align ratepayer and shareholder interests by creating "incentives of a sufficient level to insure that utility investors and managers view energy efficiency as a core part of the utility's regulated operations that can generate meaningful earnings for its shareholders."[6] The incentive mechanism also aimed to protect ratepayers' financial investment in energy efficiency, ensure that program savings are real and verified, and impose penalties for substandard performance.

The RRIM includes a Minimum Performance Standard (MPS), which is the minimum level of savings that IOUs must achieve relative to the Commission-adopted savings goal before accruing any earnings. IOU savings are based on overall portfolio performance, rather than the energy savings performance of each individual measure and program. The IOUs must achieve a minimum of 80% of the savings goals for each of three individual savings metrics (MW, GWh, and MTherms), *and* achieve a minimum of 85% of the savings goals, based on a simple average of the percentage achieved for each individual goal.[7]

If a utility meets the MPS and is eligible for shareholder incentive rewards, the specific amount is determined by applying a "shared savings rate" associated with a given level of goal achievement to the Performance Earnings Basis (PEB), which represents an estimate of the net benefits created by the utility portfolios.

Earnings begin to accrue at a 9% sharing rate if the utility meets the individual thresholds and 85% of the Commission's savings goals adopted in D04-09-060. If the utility meets 100% of the goals, earnings increase from 9% to 12%. Conversely, if utility portfolio performance falls to 65% of the adopted savings goals or lower, financial penalties begin to accrue. There are two penalty provisions and the greater of the two applies when savings fall to (or below) the 65% threshold. "Per unit" penalties are $.05 per kWh, $.45 per therm and $25 per kW for each unit below the savings goal. Should performance fall below 50% of the savings goals, penalties associated with the cost-effectiveness guarantee are expected to become larger than per-unit penalties and shareholders are obligated to pay ratepayers back dollar-for-dollar for negative net benefits. There are no earnings penalties within what is called a "deadband" range of performance greater than 65% and less than 85% of goals achievement. The earnings and penalties are capped at $450 million for all four IOUs.

Over the course of a three-year program cycle, there are two "progress payment" interim earnings claims from the IOUs, based on verified measure installation and cost reports combined with *ex ante* (pre-installation) performance estimates, with a final true-up claim to determine the level of net benefits (PEB) and MW, GWH and MTherm savings produced by the portfolio over the three year period. Thirty percent of the interim claims are held back with their ultimate disbursement dependent upon the final true-up, which is based on *ex post* (after installation)

[6] D.07-09-043, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/73172.PDF, as modified by D.08-01-042, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/78370.PDF

[7] In D.07-09-043, the Commission established an MPS of 80% for SoCalGas, because it is subject to a single goal (for MTherms) and consequently has less flexibility than the other IOUs in meeting an average MPS of 85%.

performance review at the end of the three-year cycle. All of these claims are linked to the Energy Division's Verification and Performance Basis Reports.[8]

The Commission intended that the RRIM be used for the 2006-2008 and subsequent program cycles, and also envisioned that it be revisited as warranted in the future. In 2009, the Commission opened Rulemaking 09-01-019 in consideration of a new RRIM framework for the 2010-2012 program cycle.

Demand Response

Listed second, in the loading order Demand Response enhances electric system reliability, reduces need for peak power, and benefits the environment by avoiding use of less efficient peaking plants. The investor owned utilities operate a suite of demand response programs, which have had an aggregated impact of 2,517 MW, the equivalent of five large power plants. Demand response (DR) is the ability of a customer to reduce his electricity usage (or shift his usage to a different time of the day) in response to a trigger such as a price signal, an emergency alert or an environmental event like changes in temperature. The intent of traditional demand response programs is to reduce demand during the peak hours (approximately between the hours of 2 pm and 6 pm in the summer months) when it is very expensive for utilities to provide electricity. Demand response benefits ratepayers in that it enables utilities to avoid building expensive new electric generating capacity (such as peak power plants) that are used for only a small percentage of the hours in a year. The avoidance of greenhouse gas emissions from those peaker plants is an additional benefit for the state. Demand response can also lower wholesale power costs as lowered demand forces power suppliers to adjust their prices downward in the energy markets. Demand response can also prevent rolling blackouts by providing additional reductions in demand when the grid is strained to meet demand. Demand response is ranked as one of the most important resources in the Commission's "loading order" second only to energy efficiency.

In June 2002, the Commission began a policy rulemaking to develop demand response as a resource to enhance electric system reliability, reduce power purchases (thereby lowering consumer costs), and to protect the environment.[9] Prior to 2002, demand response programs were limited to programs that were useful only for avoiding rotating outages. The Commission outlined several policy objectives from the 2002 rulemaking that remain today:

- Emphasizing "price-responsive" demand response programs,
- Affirming the importance of time-based rates to incent demand response programs,
- Implementing cost-effective advanced metering systems with enough functionality to support demand response programs, and
- Promoting the importance of customer education and technology assistance to help customers understand and participate in demand response programs.

[8] The Energy Efficiency 2006-2007 Verification Report, issued in February 2009; the Energy Efficiency 2006-2008 Verification Report; and the Final staff report to be issued in June 2010.
[9] D0511009 at section 1.

Demand response is administered in the form of retail incentive programs and retail electricity rates operated by California's three regulated investor-owned utilities (IOUs): PG&E, SCE, and SDG&E. Aggregators, otherwise known as curtailment service providers, also play a role by operating DR incentive programs on behalf of the IOUs. Most demand response programs target large commercial and industrial (C&I) customers that are already equipped with advanced (smart) meters that are capable of measuring and reporting energy usage in one hour intervals or less. The ability to track energy usage at such detailed levels is necessary for a customer to participate in demand response programs. By 2012, all IOU customers will be equipped with advanced (smart) meters thereby enabling demand response participation for all customer classes.

Commission's Actions to Improve the Efficacy of the Demand Response Programs

- **Measuring Cost-Effectiveness:** The Commission is in the process of developing demand response (DR) cost-effectiveness protocols to provide a method for measuring the cost-effectiveness of demand response resources. This protocol will be a tool in ensuring that future DR incentive programs will be cost-effective relative to a new peaker plant (which would otherwise be needed if not for the DR resource). The protocols support the fact that electricity customers, due to smart meter deployment and dynamic rates, are able to adjust their electricity loads to provide different levels of load reduction in response to price signals or other incentives. These load reductions provide value to the grid not only during emergencies, but also during times of high energy prices or in the ancillary services market. The protocols also acknowledge the fact that the methods we use to measure the costs and benefits of demand response must be flexible enough to capture these newly emerging benefits. Specifically, the protocols aim to a) address the broad variety of DR resources, including current programs and anticipated future activities; b) identify all relevant quantitative and qualitative inputs that are important for determining the cost-effectiveness of DR; c) recommend methods for determining the value of the inputs; and d) determine a useable overall framework and methods for evaluating the cost effectiveness of each of the different types of DR activities.

- **Implementing Dynamic Rates:** In addition to ensuring that DR incentive programs are evaluated for cost-effectiveness, the Commission, as noted previously, is emphasizing the use of time-based or dynamic rates to efficiently reduce demand. Time-based rates are rates that are designed to more accurately reflect the "real-time" cost of electricity. One example of a time-based rate is "Critical Peak Pricing" or CPP. CPP contains a very high energy rate that is triggered by extreme conditions such as high temperatures. The customer is warned a day in advance that the peak hour energy rate (typically from 2 pm to 6 pm) will increase significantly and the customer is advised to reduce their demand during those peak hours. The intent of this rate is send end-use customers accurate price signals for their energy use.

  Dynamic rates can further reduce costs for ratepayers when compared to traditional demand response programs. Traditional demand response programs often pay participants a financial incentive for the amount of energy they reduce during periods of peak demand. A dynamic rate eliminates the costs, both direct and administrative, of paying incentives, and instead uses an accurate price signal as the decision point for ratepayers to make choices about their energy use.

Dynamic rates will provide ratepayers with options that will reduce upward pressure on electricity rates. As customers respond to dynamic price signals, system-wide electricity demand will be lowered during peak demand periods. In the short run this will reduce prices paid by utilities to power generators in the, more expensive, short-term electricity market. In the long run, this will reduce the need for new generation plants to provide power and for transmission infrastructure to deliver that power.

The Commission has adopted a policy of "default" dynamic rates for most customer classes. Default means that the affected customer class is placed on the rate, with an opportunity to opt-out. Over the next few years, default dynamic rates will be rolled out by each IOU, starting with the largest customers in 2010.

- **Smart Meter Deployment**: The Commission has authorized the three IOUs to replace existing electricity and gas meters with smart meters over the five period spanning 2008-2012. While the cost of the new meter systems is about $4.5 billion, the Commission authorized the investment because the anticipated benefits of the new system are expected to exceed the costs over the 20-year life of the meters. The meter rollout effort will lay the groundwork for a more modern, reliable and flexible electricity grid. For example, smart meters will enable the IOUs to detect outages on the system, which means quicker restoration of service and thus less disruption to homes and businesses. As noted earlier, smart meters will measure electricity usage in time increments which enable customers to participate in demand response programs and time-based rates. Smart meters also enable customers to see their daily electricity usage and in the near future customers will be able to pre-program appliances that communicate directly with the smart meter. Armed with better information and technology, IOU electricity customers will be better able to influence their electricity usage and thus save money on their monthly electric bills.

- **Wholesale market initiatives:** In 2009, the California Independent System Operator (CAISO) implemented several major enhancements to California wholesale energy markets through its Market Redesign and Technology Upgrade (MRTU) program. MRTU is predicted to bring increased grid and market efficiencies, reduces barriers to alternative resources of power such as demand response and green generators, and gives grid operators new tools for managing transmission bottlenecks and dispatching the least cost power plants. The Commission and CAISO are working together to design and/or modify existing retail demand response programs so that the demand response MWs generated from these programs can participate in the various wholesale markets for electricity, including ancillary services. The ability to bid demand response as a resource into wholesale markets can help to mitigate local transmission constraints, provide economic benefit, and enhance grid reliability at lower costs.

Renewable Portfolio Program (RPS)

Listed third in the loading order, California's Renewable Portfolio Program (RPS) is the most ambitious in the country with a goal to supply 20 percent of the retail electricity provided by investor owned utilities, energy service providers, and community choice aggregators from eligible renewable resources by 2010.

Public Utilities Code Section 399.11 – 399.19 (established in 2002 under Senate Bill (SB) 1078 and modified in 2006 under SB 107), requires investor-owned utilities (IOUs), electric service providers (ESPs) and community choice aggregators (CCAs) regulated by the California Public Utilities Commission (CPUC) to procure an additional 1% of retail sales per year from eligible renewable sources until 20% target is reached in 2010. The CPUC and the California Energy Commission are jointly responsible for implementing the program. Governor Schwarzenegger's Executive Orders S-14-08, issued on November 17, 2008, and S-21-09, issued on September 15, 2009, established a further goal of 33% renewable energy by 2020.

Cost Containment

SB 1078 established the supplemental energy payments (SEPs) program to contain the total costs of the RPS program. Under the SEPs program, renewable generators could request SEPs from the California Energy Commission, which held a limited amount of funds available for eligible above-market costs. In 2007, SB 1036 modified the cost containment program. Instead of generators requesting SEPs, electrical corporations are now required to seek approval of both the contract and cost recovery of any eligible above-market contract costs from the CPUC at the same time.

The CPUC calculates a market price referent (MPR) annually, which represents the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine. Pursuant to SB 1036, the total amount of eligible above-market funds (AMFs) available to all electrical corporations to cover above-MPR costs for RPS contracts was the amount of SEPs that already had been collected plus the SEPs that would have been collected through January 1, 2012. The CPUC calculated that the above-MPR funds would be approximately $775 million, and they were allocated to Bear Valley Electric Service, Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison in proportion to their contribution to the SEPs fund. By the fall of 2009, the three large IOUs had exhausted their AMFs.

IOUs have no obligation to purchase RPS contracts at above-MPR prices once their AMFs are exhausted; however, they can still choose to do so and request a determination of price reasonableness from the CPUC. The CPUC continues to review RPS contract prices based on bid supply curves, least-cost best-fit analysis, consistency with each IOU's Commission-approved RPS Procurement Plan and additional data as needed.

As of January 2010, the CPUC had approved 137 RPS contracts for more than 12,000 MW of renewable capacity; as of the same date, about 1,050 MW of that renewable capacity was online, including 357 MW that began operation in 2009. Since ratepayers do not pay for RPS generation until it is actually delivered and since most of the projects resulting from RPS contracts are still in development, the rate impacts of the RPS program are currently small. .

Assuming the 33% by 2020 RPS requirement remains in place, RPS solicitations are likely to continue to receive robust responses. For example, the IOUs' 2009 RPS solicitation bids resulted in more proposed renewable generation than any other solicitation in RPS history. Developers offered to supply enough renewable generation to provide 50% of the IOUs' total load in 2020.

It also appears likely that, while some RPS-eligible technology costs are decreasing (e.g. solar photovoltaic), RPS contract prices for delivered energy will continue to move upward in general. The number of RPS contracts with prices above the MPR has increased in recent solicitations. The first above-MPR contract was approved in 2007, and since then, nearly half of the projects submitted for CPUC approval have been above the MPR. Price increases are due to at least two factors: many of the better-resourced wind projects in California are already under contract, and relatively expensive solar thermal technologies are making up a large portion of new RPS bids. The CPUC has estimated that in 2020, the total statewide electricity expenditures of achieving a 33% RPS utilizing the current procurement strategy will be 10.2% higher compared to an all-gas scenario. However, improvements in technology or other developments may create downward pressure on prices.

Proceedings in next 12 months that will impact revenue requirements or rates

- **RPS policy development proceeding (R.06-02-012):** The CPUC will consider whether to authorize the procurement and use of tradable renewable energy credits (TRECs) for RPS compliance. As discussed in the next section, allowing TRECs for compliance could significantly reduce program costs by increasing procurement flexibility.

- **RPS implementation proceeding (R.08-08-009):** In between the RPS program and self-generation programs is an important, untapped market segment for system-side renewable distributed generation (DG). In 2010, CPUC will begin implementation of SB 32, enacted in 2009, which expands the existing feed-in tariff (FIT) for renewable DG systems of up to 1.5 MW to become available to systems up to 3 MW. Because the market price referent that stands as the current FIT price already reflects the cost of fossil fuel generation and the value of environmental compliance costs, Energy Division staff does not anticipate price increases as a result of SB 32 requirements. In 2010, CPUC may also consider approving a staff proposal to create a renewable auction mechanism for systems of 1 to 20 MW (separate from the general RPS procurement process of one annual solicitation per IOU, so that smaller projects do not have to compete on price with large) that uses a standard contract and a market-based pricing structure to set competitive contract prices that are high enough to support substantial numbers of new projects.

- **Renewable transmission proceedings (R. 08-03-009 and I. 08-03-010):** As more wind and solar comes online, the State will face a growing challenge to integrate higher intermittent renewable penetration without decreasing system reliability. As a result, the California Independent System Operator (CAISO) has initiated a study of the ancillary resources necessary to maintain grid reliability with a 33% RPS. In 2010, the CPUC's renewable transmission proceeding may determine whether ISO's results warrant an integration cost adder greater than zero for RPS contracts. To the extent that the application of such a cost adder in the IOUs' bid review processes results in changes to the IOUs' procurement decisions, it may affect the overall cost of the RPS program.

- **Applications for utility solar photo voltaic (PV) programs (A.08-03-015, A.08-07-017, and A.09-02-019):** In 2010, the CPUC will consider whether to approve requests from PG&E and SDG&E to a) build, own and operate hundreds of megawatts of PV, and 2) execute contracts for several hundred more megawatts of PV to be owned and operated by independent power providers. The CPUC approved SCE's PV program in 2009.

Actions for reducing rate impacts in the next 12 months:

- **Tradable Renewable Energy Credits (TRECS):** In March 2010, the Commission authorized the use of TRECs for RPS compliance whereby the LSEs can choose not to receive delivered energy for some portion of their renewable obligation. Allowing the use of TRECs for RPS compliance generally will provide more renewable procurement options and flexibility for LSEs, potentially resulting in lower costs to ratepayers. A transitional price cap for TRECs was included, protecting ratepayers further from high prices in the early stages of a TREC market. However, due to industry opposition to the CPUC decision and numerous requests to modify the decision filed shortly after it was rendered, the decision has been stayed to allow the CPUC to evaluate further TREC policy. This reevaluation is expected to be completed in 2010.

- **Renewable Auction Mechanism:** CPUC staff's proposed renewable auction mechanism and the utility PV programs could both be helpful in minimizing program costs. PV prices have decreased substantially in the last year and are often cheaper than bid prices for utility-scale solar thermal projects, which currently represent a large portion of proposed new RPS projects. If these programs are successful at spurring significant increases in PV capacity, economies of scale could prompt installed PV costs to decline further.

Distributed Generation/ California Solar Initiative

The California Solar Initiative (CSI) is overseen by the California Public Utilities Commission (CPUC) and provides incentives for installation of solar energy systems to customers of the state's large regulated utilities. The CSI Program demonstrates the State's strong support for solar technology and is an outgrowth of Governor Schwarzenegger's call for a "Million Solar Roofs" vision for the State of California.[10]

[10] The Million Solar Roofs goal was not adopted by the Legislature as an explicit number of projects goal in its authorization of the State's solar programs. Instead, the Legislature adopted a 3,000 MW capacity goal. However, if the entire capacity goal were installed (hypothetically) in only small residential systems averaging 3 kW in size, it would cover approximately one million roofs. In practice, the CPUC expects its CSI-electric portion of the statewide program to be approximately one-third residential, and two-thirds non-residential projects. Since non-residential systems are fewer in number, but larger in terms of per-project capacity, the number of systems installed will not reach one million even when the capacity targets are achieved.

The CSI is funded in two different ways depending on the type of energy that is being displaced. Electric ratepayers support solar energy systems that displace electricity, and gas ratepayers support systems that displace onsite consumption of natural gas. In both cases, CSI provides upfront incentives for solar systems installed on existing residential homes, as well as existing and new commercial, industrial, government, non-profit, and agricultural properties within the service territories of the large IOUs.

The CSI Program focuses on onsite, grid-connected[11] solar technologies used by utility customers to offset some portion of their own load. The CSI Program does not fund wholesale solar power plants, designed to serve the electric grid or help utilities meet Renewable Portfolio Standard (RPS) obligations.[12]

In early 2006, the Commission, in collaboration with the California Energy Commission, established the CSI as a $2.5 billion incentive program to promote solar development through 2016, to be funded from the distribution rates of gas and electric ratepayers.[13] At that time, the Commission stated its intent to consider incentives for solar water heating as part of the CSI program, and directed San Diego Gas & Electric Company (SDG&E) to contract with California Center for Sustainable Energy (CCSE) (formerly the San Diego Regional Energy Office) to administer a pilot program for SWH incentives in the SDG&E territory.

Subsequently, with the passage of Senate Bill (SB) 1 (Murray, 2006) in August of 2006, funds for CSI were limited to $2.167 billion and could no longer be collected from gas ratepayers. The CPUC authorized rate collections for the three large electric investor-owned utilities (large IOUs): Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and SDG&E. At the same time, SB 1 included a provision allowing $100.8 million of total CSI funds to be used for incentives for solar thermal technologies, such as solar water heating.[14] With CSI funding now limited to collections from electric ratepayers, the Commission concluded in Decision (D).06-12-033 that CSI should only pay incentives to solar thermal technologies that displace electric usage.[15] The SWH pilot in the SDG&E territory, budgeted at $3 million, was allowed to proceed to provide useful information on SWH incentives in general.

In late 2007, the Governor signed Assembly Bill (AB) 1470 (Stats. 2007, Ch. 536), authorizing the creation of a $250 million incentive program to promote the installation of 200,000 SWH systems in homes and businesses that displace the use of natural gas by 2017. The statute requires the Commission to evaluate data from the SWH pilot and determine whether an SWH program is "cost effective for ratepayers and in the public interest" before designing and implementing an incentive program for gas customers.[16]

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[11] Strictly speaking, solar thermal systems are not grid connected, but back-up hot water or thermal service is provided by the gas distribution network.
[12] The California utilities contract for a variety of renewable resources, including large and small solar power plants as part of the RPS Program. Updates on the progress of the RPS program can be found at http://www.cpuc.ca.gov/PUC/energy/Renewables/.
[13] See Decision (D.) 06-01-024.
[14] See Pub. Util. Code § 2851(b).
[15] D.06-12-033, Conclusion of Law 19 at 38.
[16] Public Utilities Code Section 2863(a)

The CSI Thermal Program will provide incentives to promote the installation of solar water heating systems in the territories of PG&E, SCE, SDGE and Southern California Gas Company (SoCalGas). The CSI Thermal Program will be funded by $250 million in collections from gas ratepayers, pursuant to AB 1470, as well as up to the $100.8 million in funds already authorized for solar thermal projects. The latter is currently being collected through the larger CSI program for electric displacing solar technology as authorized by SB 1 and Commission decisions. Monies collected under AB 1470 from gas ratepayers will fund incentives to solar water heating systems that displace natural gas usage, while funds collected under SB 1 from electric ratepayers will fund electric displacing solar water heating systems.

The CSI Thermal Program will be administered by PG&E, SCE, SoCalGas, and by CCSE in SDG&E territory. PG&E and SDG&E, in coordination with its program administrator, CCSE, will disburse incentives to both electric and gas ratepayers who install eligible solar water heating systems in their territories. SCE will disburse incentives through the CSI Thermal Program to customers who install electric displacing solar water heating systems. SoCalGas will disburse incentives to customers in its territory who install gas displacing solar water heating systems.

Proceedings in next 12 months that will impact revenue requirements or rates

The electric displacing portion of the CSI Program has a budget of $2.167 billion over 10 years, from 2007-2016. The CSI Thermal Program has an additional budget of $250 million through 2017. Together, this funding is intended to:

- Install 1,940 MW of distributed solar energy systems in the large IOU service territories;
- Install solar water heating systems that displace 275.7 million kWh per year of electricity;
- Install solar water heating systems that displace the use 585 million therms of natural gas in homes and businesses in the large IOU service territories;
- Transform the market for solar energy systems so that it is price competitive and self-sustaining.

The CSI Program has seven program components, as shown in Table 1, each with their own Program Administrator and budgets that are overseen by the CPUC:

- **The CSI General Market Solar Program** is administered through three Program Administrators: PG&E, SCE, and CCSE in SDG&E territory. The goal is 1,750 MW with a ten-year budget of $1.8 billion.
- **The CSI Single-family Affordable Solar Homes (SASH) Program** provides solar incentives to qualifying single-family low income housing owners. The SASH Program is administered through a statewide Program Manager, GRID Alternatives, with a budget of $108 million through 2015.
- **The CSI Multifamily Affordable Solar Housing (MASH) Program** provides solar incentives to multifamily low income housing facilities. The MASH Program also has a

$108 million budget through 2015 and is administered through the same Program Administrators as the general market solar program: PG&E, SCE, and CCSE.

- **The CSI Research, Development, Demonstration and Deployment (RD&D) Program** provides grants to develop and deploy solar technologies that can advance the overall goals of the CSI Program, including achieving both targets for capacity, cost, and a self-sustaining solar industry in California. The RD&D Program is administered through the RD&D Program Manager, Itron, Inc., and has a budget of $50 million.
- **The CSI Solar Water Heating Pilot Program (SWHPP)** provides solar hot water incentives through a pilot program for residences and businesses in the San Diego area only; the SWHPP is administered through CCSE with a budget of $2.6 million.
- **The CSI Thermal Program** provides rebates for solar water heating (SWH) installations on new and existing homes and businesses. The program will pay incentives towards SWH systems that displace natural gas water heating on new[1] and existing homes and businesses, and towards SWH systems that displace electric water heating on existing homes and businesses. The goal is 585 million therms of natural gas displacement with a budget of $250 million on the gas side, and 275.7 million kWh per year of electricity displacement (the equivalent of 150 MW of electric generating capacity) with a budget of $100.8 million on the electric side.

Table 1: CSI Budget by Program Component, 2007-2017

	Budget ($ Millions)	**Goal (MWs)**
General Market Solar Program	$1,797	1,600 MW
Single-Family Affordable Solar Homes (SASH)	$108	95 MW
Multifamily Affordable Solar Housing (MASH)	$108	95 MW
Research, Development, Demonstration, and Deployment (RD&D)	$50	~
Solar Hot Water Pilot Program (SWHPP)	$2.6	750 SWH systems
Solar Thermal Program, Gas-displacing	$250	585 million Therms
Solar Thermal Program, Electric-displacing[17]	$100.8	150 MW
Total CPUC CSI Budget	**$2,417**	**1,940 MW 58.5 MMDth**

Source: CPUC D.06-12-033, p.26 and CPUC D.10-01-022, Appendix A. Figures may not sum to total because of rounding.

[1] If SWH becomes mandatory for new home construction, new homes shall not be eligible for incentives under CSI Thermal.

[17] The 150 MW goal for the Thermal Program Electric-displacing portion of CSI is already included in the MW goals for the CSI General Market Program.

CSI Program Balancing Accounts

In D.06-12-033, the Commission established a total budget of $2.167 billion over ten years for the CSI, including all program components. The large IOUs were authorized to collect the CSI Program funds from electric ratepayers according to the schedule as shown in Table 2.[18] The CSI funds are held by each utility in a balancing account, which is a standard utility accounting practice. The CSI schedule of collection is slightly front-loaded for a number of reasons, including ensuring that participants applying for CSI incentives today can be confident that the funds will be available for their projects upon completion.

Table 2: Authorized CSI Balancing Account Rate Collection Schedule

Year	PG&E	SCE	SDG&E	Total
Transfer from SGIP on 12/31/2006	$ -	$ 104,600,000	$ 37,200,000	$ 141,800,000
2007	$ 140,000,000	$ 147,000,000	$ 33,000,000	$ 320,000,000
2008	$ 140,000,000	$ 147,000,000	$ 33,000,000	$ 320,000,000
2009	$ 140,000,000	$ -	$ -	$ 140,000,000
2010	$ 105,000,000	$ 110,000,000	$ 25,000,000	$ 240,000,000
2011	$ 105,000,000	$ 110,000,000	$ 25,000,000	$ 240,000,000
2012	$ 105,000,000	$ 110,000,000	$ 25,000,000	$ 240,000,000
2013	$ 70,000,000	$ 74,000,000	$ 16,000,000	$ 160,000,000
2014	$ 70,000,000	$ 74,000,000	$ 16,000,000	$ 160,000,000
2015	$ 70,000,000	$ 74,000,000	$ 12,800,000	$ 156,800,000
2016	$ 2,000,000	$ 45,400,000	$ -	$ 47,400,000
Total	**$ 947,000,000**	**$ 996,000,000**	**$ 223,000,000**	**$ 2,166,000,000**

Source: D.08-12-004

Actions for reducing rate impacts in the next 12 months

Over the next few years, the CPUC will continue to monitor the trends in expenditures from CSI relative to costs and will adjust the necessary revenue collections by the utilities accordingly.

CARE and Low Income Energy Efficiency (LIEE)

The Commission's low income assistance is conducted through two programs. The California Alternate Rate for Energy (CARE) Program provides eligible low-income households with a discount on electric and natural gas bills and the Low Income Energy Efficiency (LIEE) Program provides eligible low-income households with energy education, energy efficient appliances, and weatherization measures at no cost.

California Alternative Rate for Energy (CARE)

[18] The CPUC modified the CSI Program rate collections schedule in December 2008, in D.08-12-004.

CARE is a low income energy rate assistance program instituted in 1989 to address energy insecurity and fuel poverty of California's low income populations. Initially, the program provided a 15% discount on electric and gas rates. The discount was increased to 20% in 2001 (D. 01-06-010). However, because of the fact that CARE customers were not subject to the high rates for Tier 4 and 5, the subsidy for CARE has grown substantially above 20% as Tier 3, 4 and 5 rates have risen over time and Tier 1 and 2 were frozen. The CARE subsidy is particularly high for PG&E which has only two CARE Tiers. Both LIEE & CARE are funded by ratepayers through the Public Purpose Program (PPP) Charge. According to the KEMA Low Income Needs Assessment 2007 report, one in three of California's households (33%) qualified for the CARE and LIEE Programs in 2006, (or approximately 4 million households statewide).

Low-income Energy Efficiency (LIEE)

The Low Income Energy Efficiency Program began in the 1980s as a direct assistance program provided by some of the Investor Owned Utilities (IOUs), and was formally adopted by the legislature in 1990 through Public Utilities Code Section 2790. Since their inception, these programs have grown significantly in size and scope. The LIEE program provides home weatherization services for low-income households and includes the following measures: (1) Heating Ventilation Air Conditioning Measures; (2) Infiltration and Space Conditioning; (3) Weatherization; (4) Water Heating Savings; (5) Energy Education; and (6) other Miscellaneous Measures including Refrigerator Replacements, Compact Fluorescent Light bulbs (CFLs) and Compact Fluorescent hardwired fixtures. Weatherization services may also include other building conservation measures, energy efficiency appliances and energy education programs, with each IOU's program portfolio being evaluated during the budget application process. All measures are provided at no cost to the resident.

As articulated in the *Energy Efficiency Strategic Plan,* the LIEE program pursues two goals:

- By 2020, all eligible customers will be given the opportunity to participate in the LIEE program

The LIEE program will be an energy resource by delivering increasingly cost-effective and longer-term savings.

Proceedings in next 12 months that will impact revenue requirements or rates

The CARE and LIEE programs are funded for a 3-year planning cycle. For the 2009-2011 budget period, the Commission authorized a $2.6 billion budget for CARE and $885 million for the LIEE (see Decision 08-11-031). This Decision also established a CARE penetration goal of 90% and an LIEE goal for all the IOUs to treat 1 million homes in California during the 2009-2011 period. The expected benefits of this spending are projected energy savings (yearly average) as follows: 81,266 MWh; 22.3 MW of demand; and 5.3 million Therms.

The tables below show the annual LIEE targets and the annual CARE and LIEE budgets.

LIEE Goals: Number of homes to be treated from 2009-2011

Utility	2009	2010	2011	Cycle
PG&E	91,099	125,261	125,261	341,622
SCE	83,612	83,612	83,612	250,837
SoCalGas	111,211	143,973	146,301	401,485
SDG&E	20,384	20,384	20,384	61,152
Total	306,307	373,230	375,559	1,055,096

Adopted Budget Summary 2009-2011				
	LIEE			
Utility	**2009**	**2010**	**2011**	**Cycle Total**
PG&E	$109,056,366	$151,067,347	$156,789,038	$416,912,752
SCE	$60,242,000	$61,561,082	$63,413,860	$185,216,942
SoCalGas	$49,571,908	$76,872,816	$78,256,269	$204,700,993
SDG&E	$21,184,008	$21,184,009	$20,327,606	$62,695,622
Total	$240,054,283	$310,685,254	$318,786,772	$869,526,309
	CARE			
	2009	**2010**	**2011**	**Cycle Total**
PG&E	$470,314,651	$479,331,337	$489,228,435	$1,438,874,423
SCE	$208,541,000	$213,312,000	$216,885,000	$638,738,000
SoCalGas	$139,132,786	$140,737,280	$142,489,637	$422,359,704
SDG&E	$49,961,816	$51,516,795	$53,064,454	$154,543,065
Total	**$867,952,262.40**	**$884,899,422.01**	**$901,669,537.33**	**$2,654,515,191.74**

Commission Actions in the Next 12 Months

While the Commission's Decision 08-11-031 significantly increased the budgets for the 2009-2011 program years, it also adopted new goals, initiatives, and improvements to the program to encourage and facilitate greater program efficiencies, collaborations and overall benefits to the low income population as well as the rest of the state. Implementation of these efforts will be central to the Commission's activities over the next 12 months, and beyond. These major initiatives will include the following:

Program Delivery, Marketing & Outreach

- Focus outreach on customers with high energy- use, burden and insecurity to reach those customers in greatest need first.
- Develop a whole neighborhood approach to market and install LIEE measures to increase program delivery efficiencies and effectiveness.
- Enhance outreach to the disabled to better reach this group that makes up approximately 20% of LIEE-eligible population.
- Implement a 90% CARE penetration goal for all IOUs in the 2009-2011 period.

- Increase the overall cost effectiveness of the program by implementing a 0.25 benefit-cost ratio threshold on measures.
- Strengthening of rules to ensure cost efficiencies, such as the requirement to at least install three measures in one visit to a household in order to achieve a threshold of energy saving.
- Focus and promotion of relevant workforce education and training.
- Focus on increasing internal and external efficiencies for the IOU's. The CPUC will assess the IOU's efforts to leverage LIEE marketing activities with other government and private programs as well as assess the IOU's efforts in integrating their own demand side programs.

Studies & Pilots to further improve program effectiveness
The CPUC authorized budgets for the following pilots and studies with the intent to use the results to further improve program delivery, customer marketing and outreach efforts, program efficiencies and cost effectiveness all while maximizing customer benefits.

- PILOTS: Microwaves, Online LIEE Training Modules for Contractors, Smartmeter and In-Home Display Pilots.
- WE&T: Workforce Education and Training: A LIEE contractor and an educational institution will work with a utility to develop and implement an in-class and hands-on curriculum to be used as part of a certificated program through the educational institution:
- 2009 Impact Evaluation Study to determine the electric and gas energy savings impacts of the LIEE program
- 2009 Process Evaluation Study of the effectiveness of the overall LIEE program that will make recommendations for improved program design and delivery
- Non-Energy Benefits Study of the potential non energy benefits of the program other than direct energy savings.

As noted above, the current budget cycle spans three years, through the end of 2011. Thus, the expected costs and rate impacts are known for the next 18 months or so. The IOUs are likely to submit applications for a 2012-2014 planning cycle in mid-2011. Through the programs described above, the state's low-income population receives benefits that include: increased health, comfort, and safety, increased education and awareness to energy efficiency and environmental issues, and greater workforce education and training opportunities within the developing green economy. The program's purpose is to improve the welfare of California's low-income population, by subsidizing and managing energy efficiency improvements for both rented and owned residences. These initiatives will yield greater efficiencies, collaborations and overall benefits to the low income population as well as the rest of the state.

V. Natural Gas Rates and Costs

Due to low natural gas prices, customers of natural gas utilities are experiencing their lowest natural gas rates in over five years. However, the CPUC does not regulate the price of natural gas. The recent low commodity price of natural gas is the result of developments in the natural gas market, which is influenced by both national and global market conditions.

Natural gas utility rates in California consist of three main components for typical "core"[19] gas ratepayers:

- the procurement rate, which recovers the cost of procurement of the natural gas itself,
- the transportation rate, which recovers the operations cost of the utility to deliver natural gas and provide various customer services, and
- the gas public purpose program surcharge, which recovers the cost of various public purpose programs such as the CARE discount, natural gas energy efficiency programs, and natural gas research and development.

California natural gas utilities operate over 100,000 miles of transmission and distribution pipelines, and deliver natural gas to over 10.5 million customers. They also operate large natural gas storage fields. The CPUC authorizes the revenue requirements for the natural gas distribution utilities primarily in the areas of natural gas transmission, distribution, storage, and customer service costs and natural gas public purpose program (PPP) costs. Natural gas utility costs for transmission, distribution, storage and customer service have moderately increased by about 3% since 2006. Gas PPP costs have increased by 20% since that time.

CPUC Actions to Limit Utility Cost and Rate Increases

The CPUC will rely on successful programs to ensure that natural gas procurement costs are reasonable. However, changes in utility core customer gas rates and costs are most heavily influenced by the price of natural gas supply.

In the coming year, the Commission expects to maintain natural gas utility rates at reasonable levels in the following manner:

- Although the Commission can not regulate the price of natural gas, it will continue to implement measures that:
  - Provide incentives to utilities to keep natural gas procurement costs low,
  - Allow expeditious approval of a diverse and reasonably-priced portfolio of interstate pipeline capacity,
  - Provides core customers with adequate amounts of natural gas storage capacity, and
  - Allows utilities to engage in efficient natural gas hedging practices.

[19] Core customers are mainly residential and small commercial customers.

- The Commission will scrutinize natural gas utility operational costs and rates for transmission, distribution and storage in several major proceedings, including the PG&E 2011 General Rate Case (GRC), the PG&E Gas Transmission and Storage proceeding, and the SoCalGas/SDG&E 2012 GRC.
- The CPUC will ensure that public purpose programs are conducted efficiently and provide the maximum benefits for which they are intended. For example, the CPUC staff will be investigating the costs of the natural gas research and development program in 2010. The other main components of the gas PPP surcharge, energy efficiency and CARE programs, are discussed in other sections of this report.

Almost all larger, "noncore" natural gas consumers (such as industrial customers or electric generators) procure their own natural gas supplies using non-utility suppliers, so they are not charged the procurement rate by the utility. In addition, electric generation and other exempt customers are not charged the gas PPP surcharge, pursuant to the Public Utilities Code Section 896.

Although core gas customers in California have the option to choose a non-utility natural gas supplier, natural gas utilities in California provide procurement service for over 98% of core customers. The major natural gas utilities recover procurement costs in a component of the total gas rate called the gas procurement rate. The gas procurement rate is changed every month to reflect the most current price of natural gas. This helps send customers a price signal, so they may adjust their usage accordingly. The procurement rates are changed routinely in monthly filings at the CPUC called advice letters.

The utility does not receive a return or mark-up for the procurement service, but the CPUC has approved gas cost incentive mechanisms for each of the four large natural gas utilities (PG&E, SoCalGas/SDG&E, and Southwest Gas).[20] Under these mechanisms, the utility can achieve small shareholder rewards if it can procure supplies at prices below the Commission approved benchmarks which are the monthly market indices.

Natural gas procurement costs have the most significant impact on the month-to-month and year-to-year changes in utility core gas customer rates for two reasons. First, the natural gas procurement rate is a large component of the total core natural gas rate. Second, natural gas prices fluctuate far more than the other two core rate components, the delivery (or "transportation") rate and the natural gas public purpose program surcharge.

Current Trends in Gas Rates

Total core natural gas rates on average are at their lowest level in at least the last five years. As one can see in the tables presented by the CPUC in its April 2010 Gas and Electric Utility Cost Report[21], the natural gas procurement costs in 2009 were 37% lower than the procurement costs in 2008. Even with the dramatic decrease in procurement costs in 2009, these costs represented about 47% of total utility costs. Because natural gas costs fell so much in 2009, and into 2010,

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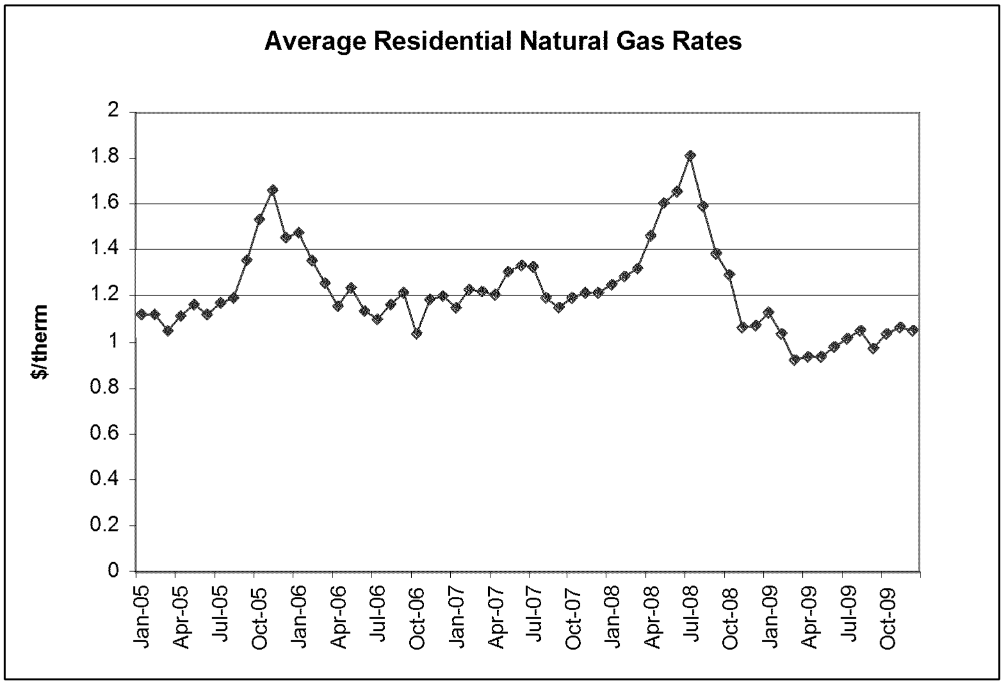
[20] SoCalGas procures natural gas for both its own core customers as well as for SDG&E core gas customers.
[21] ftp://ftp.cpuc.ca.gov/OGA/reports/2010/Final%20Cost%20Report_2.pdf

procurement rates also fell dramatically. The decline in the procurement rate has caused the total core natural gas rate to fall to its lowest average level in at least 5 years, as shown in the graph below. As of the date of this report, market indications of the futures price of natural gas price show that prices are expected to remain moderate on average in the coming 12 months.



The CPUC Can Only Influence the Bulk of Procurement Costs Indirectly

The bulk of the utility gas procurement costs consist of the costs of the natural gas supply itself. Other costs in the gas procurement rate include: the costs of interstate pipeline capacity, the costs or gains associated with hedging, and some intrastate transmission costs. (PG&E also includes the costs of storage capacity allocated to core customers in the gas procurement rate.) The major natural gas utilities change the procurement rate they charge core gas customers every month.

Noncore customers directly buy their own gas, so the CPUC doesn't have knowledge about what specific noncore customers pay. But, as confirmed by data from the Energy Information Administration, noncore customers are also generally experiencing their lowest natural gas costs in about six or seven years.

The price of natural gas is not regulated by the CPUC or the Federal Energy Regulatory Commission (FERC), and is generally determined by market forces. The CPUC does not have the jurisdiction to regulate natural gas prices, and the FERC deregulated the price of natural gas in the 1980's.

The CPUC also cannot directly impact the cost of interstate pipeline capacity used to transport core gas supplies to California from out-of-state basins. The tariff rates of interstate pipelines are determined by the FERC. The utilities can occasionally obtain discounted rates for interstate pipeline capacity but this is largely influenced by market forces. (However, as explained below, the CPUC does intervene at FERC on pipeline rate cases, and the CPUC tries to ensure that the utilities obtain pipeline capacity at low cost.)

The CPUC works to ensure that the utilities do a reasonable job procuring natural gas supplies at low cost for core customers. The CPUC does this by:

- Adopting gas cost incentive mechanisms, which provide a financial incentive to the utilities to procure natural gas supplies at the lowest cost,
- Adopting an expeditious process for approvals of beneficial interstate pipeline capacity contracts for transportation of supplies from out-of-state supply basins to California,
- Allocating adequate utility storage capacity to core customers, and
- Allowing efficient natural gas hedging of gas prices.

During the next 12 months, the CPUC will continue to utilize the above practices to keep procurement costs reasonable.

Gas Cost Incentive Mechanisms

The CPUC expects that the utilities will continue in the coming year to diligently endeavor to achieve natural gas savings relative to monthly gas price indices, as they have done in the past, under their gas cost incentive mechanisms. Gas cost incentive mechanisms have been adopted for PG&E, SoCalGas, and SDG&E since the mid-1990's, and for Southwest Gas since the mid-2000's. These mechanisms provide a financial incentive for the utilities to procure natural gas for core customers at below monthly market prices. (When utilities do a poor job procuring natural gas supplies, they face a penalty.) The CPUC has made various modifications to the mechanisms over the years, but at this time does not anticipate making any significant changes to these mechanisms during the next year. The gas cost incentive mechanisms have been successful because, in almost every year since their adoption, utilities have procured gas supplies at a savings relative to market prices.

Gas Hedging

The CPUC recently ordered a major change in how the utilities' hedging costs or gains are treated to encourage efficient use of hedging. Since 2005, the CPUC has allowed a significant increase in the winter hedging activity conducted by the utilities in order to guard against the risk that natural gas prices will dramatically increase during the winter. Along with the increase in hedging activity, the CPUC allowed the utilities to pass on all hedging costs/gains to procurement customers. While the hedging programs helped insure that core customers would not pay extremely high prices, these hedging programs came with big costs. As the CPUC's April 2010 Gas and Electric Utility Cost Report[22] shows, the utilities have been incurring hedging costs that amounted to tens of millions of dollars per year. In order to ensure that the utilities manage their hedging programs efficiently, in January 2010 the CPUC required utilities to include a portion of these costs or gains under the gas cost incentive mechanisms. This

[22] ftp://ftp.cpuc.ca.gov/OGA/reports/2010/Final%20Cost%20Report_2.pdf

effectively places the utilities at some risk for the hedging costs/gains. With the change ordered by the CPUC in January 2010, we expect that future hedging activity will be more efficiently managed than in the past.

Interstate Pipeline Capacity Contracts

During the next 12 months, the CPUC expects that the utilities will continue to obtain reasonable interstate pipeline capacity contracts under the expedited approval process. In 2004, the CPUC authorized an expedited process for approvals of new interstate pipeline capacity contracts held between the natural gas utilities and large interstate pipeline companies. The CPUC also specified a minimum level of capacity to be held by the utilities in order to reliably serve core gas customers' supply needs. These contracts allow the utilities to transport natural gas supplies from out-of-state gas supply basins to California with a high degree of reliability. Under the expedited approval process, the utilities have gradually diversified their interstate pipeline portfolios. Formerly, the utilities held a small number of long-term contracts, but they now have in place a variety of contracts with different terms, better prices, and greater supply access. In addition, the approval process takes much less regulatory time for both the CPUC and the utilities, and allows the utilities to act more quickly to obtain the best deals.

In order to maintain adequate transportation capacity to the supply basins, a number of contracts will need to be signed in the coming year by the utilities, as old contracts expire. As discussed later in this report, the CPUC also intervenes at the FERC on interstate pipeline general rate cases in order to keep pipeline rates down for all California gas consumers.

The Ruby Pipeline

A major new interstate pipeline, the Ruby Pipeline, is expected to begin deliveries to California in early 2011. The CPUC approved major PG&E contracts on the Ruby Pipeline in 2008. The Ruby Pipeline will be the first new major interstate pipeline to California in over 15 years, and is expected to begin operation in the first quarter of 2011 if FERC approval of a construction permit is gained soon. The Ruby Pipeline will further improve California's access to a diverse portfolio of supplies, including for PG&E's core gas customers. Diversity of supplies not only helps to ensure adequate supply, but also over time helps to keep procurement costs moderated, as utilities can shift from higher priced basins to lower-priced basins when market conditions change. The Ruby Pipeline will provide the first significant supplies from the Rockies to northern California.

The CPUC approved two large interstate capacity contracts for PG&E on the Ruby Pipeline back in late 2008. One of these contracts is for core gas supply, and the other contract is for gas supplies for PG&E electric generation. The CPUC approval of the PG&E contracts was a critical component in the development of the Ruby Pipeline project.

Storage Capacity

Core customers have reasonable amounts of storage capacity and may be obtaining additional storage in the near future. The utilities own large storage fields, and significant portions of that capacity are allocated to the utilities' core customers. The remainder of the capacity is made available to larger "noncore" customers and marketers. This allocation not only helps to ensure deliveries to core customers with a high degree of reliability, but also allows the utilities to take advantage of the economic benefits of storage, which can then be passed on to their procurement customers. Natural gas prices fluctuate daily and are typically lower in the summer than in the winter. Storage allows the utilities flexibility to buy more gas when prices are low and withdraw the gas when prices are high. From time to time, the utilities may also be authorized to obtain additional storage from the independent storage utilities, Wild Goose Storage and Lodi Gas Storage.

In the coming year, the CPUC does not expect a significant shift in utility storage capacity allocated to core customers, but some additional capacity could be authorized. The allocation of PG&E and SoCalGas storage capacity to core customers has already been set in various past CPUC proceedings, and some additional capacity has been authorized from the independent storage operators. The CPUC recently approved an application by SoCalGas which provides for additional core storage capacity at its Honor Rancho storage field. In addition, it is possible that storage capacity could be obtained from independent storage providers or utility-owned storage if it is economic and/or improves delivery reliability.

Rate Related Proceedings in Next 12 Months

During the next 12 months, in order to ensure that utility revenue requirements and rates for transmission, distribution, storage, and customer services are reasonable, the CPUC will be scrutinizing these costs and rates in several major proceedings to ensure that only reasonable costs and rates are authorized. During the next 12 months, the CPUC expects to examine natural gas utility costs in the following proceedings:

PG&E

PG&E Gas Transmission and Storage (GT&S) Rate Proceeding A.09-09-013

PG&E is proposing its revenue requirement for its gas transmission and storage system for the years 2011 through 2014. The revenue requirement would be used for GT&S operating and maintenance expenses and capital expenditures. In the proceeding, the utility also is proposing the rates it would assess its customers for the recovery of its GT&S revenue requirement.

PG&E's gas transmission and storage system is critical infrastructure. The utility's gas transmission pipelines (referred to as "backbone" pipelines) consist of large-diameter, high pressure pipelines, which receive gas from various interstate pipelines, California gas producers, and storage fields, and deliver this gas to PG&E's local transmission system, directly to end-use customers, or to off-system markets, primarily in southern California. PG&E's local transmission facilities, which are interconnected with the utility's backbone system, deliver gas to many large end-use customers as well as to PG&E's distribution system. The utility also operates gas storage fields that serve both residential and nonresidential customers.

PG&E's Gas Transmission and Storage Revenue Requirement Request ($ millions)

Service Component	2010	2011	2012	2013	2014
Backbone transmission	241.0	234.0	247.5	260.1	263.7
Local transmission	164.0	202.8	219.5	235.3	252.7
Storage	51.6	87.6	89.5	91.8	93.1
Customer Access	5.2	4.7	5.0	5.1	5.3
Total	**461.8**	**529.1**	**561.5**	**592.2**	**614.8**

A.09-09-013, Table 1-1

PG&E says its requested revenue requirement increase is needed to provide its customers with safe, reliable and efficient service as well as to meet growing demand. In particular, PG&E claims that it is experiencing increased capital outlays for its gas transmission pipelines well above historical levels, primarily due to the age of its facilities, and is proposing capital outlays for the four year period of $843.9 million.

Operating and maintenance expenses are expected to escalate for a variety of reasons. These include compliance with a federal pipeline safety inspection mandate, compressor maintenance and overhaul expenses, and costs associated with the operation of PG&E's Gill Ranch gas storage facility, currently under construction.

PG&E is also proposing the creation of a revenue sharing incentive mechanism. Under this mechanism, PG&E will share with its gas transmission customers 50% of the difference between its adopted and recorded GT&S revenue requirement. This means that if collected GT&S revenues exceed the adopted revenue requirement, PG&E will return half this amount back to its transmission customers through a rate adjustment. On the other hand, if collections are fall below the GT&S revenue requirement, the utility will recover half of the shortfall from its transmission customers and absorb the remainder. Currently, PG&E is at-risk for most of its GT&S revenue requirement with the utility retaining collected GT&S revenues.

PG&E has projected that the recovery of its proposed GT&S revenue requirement will result in a 1.4% increase in residential bundled core rates.

The CPUC's Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN, a consumer advocacy group), and other parties have intervened in the proceeding to represent the interests of PG&E's ratepayers. The CPUC expects to issue its decision in this proceeding in late 2010 or early 2011.

PG&E Biennial Cost Allocation Proceeding (BCAP)

In A. 09-05-026, PG&E is presenting its proposed allocation of the adopted gas distribution revenue requirement[23] among its core and noncore customer classes. PG&E's gas distribution revenue requirement is $1.09 billion and was adopted in D.07-03-044, in the utility's last General Rate Case. In this proceeding, the Commission will adopt the cost allocation and gas rates PG&E will assess its customers to recover its gas distribution revenue requirement. The cost allocation will affect the level of rates PG&E will charge its residential, commercial and industrial customers.

Adopting PG&E's proposals will result in a 2.0% increase in the rates for the utility's bundled residential customers. DRA, TURN and others have intervened in the proceeding to represent the interests of ratepayers. An agreement has been reached on the majority of the contested issues. The CPUC expects to issue its decision in this proceeding in 2010.

PG&E 2011 General Rate Case (GRC)

In A.09-12-020 (2011 General Rate Case), PG&E is, among other things, requesting an increase in its authorized 2011 gas distribution revenue requirement. The utility is also requesting additional amounts for the future, "attrition" years 2012 and 2013. PG&E's gas distribution system consists of pipelines with operating pressure at 60 pounds per square inch (psi) or less and generally connect local transmission lines to its end-use customers.

The following table summarizes PG&E's A.09-12-020 gas distribution revenue requirement request.[24] ($ in thousands)

Gas Distribution Revenue Requirement

2011	2012	2013
$1,297,444	$1,350,710	$1,416,707

As noted above, PG&E's current gas distribution revenue requirement is $1.09 billion, so PG&E is requesting a significant increase in its gas distribution revenue requirement. PG&E's request would result in a 5.7% increase in a typical bundled residential core monthly bill. The 2011 gas distribution revenue requirement is based on costs PG&E forecasts it will incur to:

- Own, operate, and maintain its distribution plant and a portion of its common and general plant;
- Perform the transactions necessary to acquire gas supplies for its core gas customers; and
- Provide services to its gas customers.

DRA and TURN as well as numerous other parties typically intervene in PG&E's GRCs. The CPUC expects to hear evidence from PG&E and interested parties in this proceeding. The CPUC hopes to issue its decision in December 2010.

[23] In the PG&E BCAP, the revenue requirement for the gas distribution pipeline system is allocated, and rates are set. The rates and revenue requirement for the larger-volume transmission system and storage assets are determined in the "Gas Transmission and Storage" proceeding.

[24] A.09-12-020, Table 2-1

PG&E Rate related request expected later this year

- Winter Gas Savings Program (2010-2011)
- Core Procurement Incentive Mechanism Shareholder Award
- Annual Electric True-Up (AET) 2011 - Advice Letter Update
- FERC TACBA Filing

SoCalGas/SDG&E

SoCalGas Storage Field Expansion

In A.09-09-020, SoCalGas is proposing to conduct work at its Aliso Canyon Storage Field Project, to replace 3 gas turbine compressors with 3 electric compressors. This project will expand storage injection capacity by 145 million cubic feet per day (mmcf/d). SoCalGas estimates the expansion cost to be $200.9 million. The project would result in an increase in core gas rates of about 0.3 cents per therm, or about $10 million per year. SoCalGas requests approval of its revenue requirement and its proposed allocation of the project costs to various customer classes. SoCalGas requests that approval of the actual costs be obtained through the Advice Letter process.

The CPUC expects to determine if it should adopt SoCalGas' proposal in 2011.

SoCalGas/SDG&E Off-System Delivery – A.08-06-006

In June 2008, SoCalGas requested approval from the Commission to make gas deliveries to outside of California from its transmission system. (At this time, SoCalGas may only make deliveries to points in California.) SoCalGas and SDG&E argue that its proposed "Off-System Delivery" (OSD) service will not degrade service to its in-state customers, will encourage storage expansion, and will increase usage on its system, which will in turn lower rates for its customers.

Other parties have submitted testimony in the proceeding that contests SoCalGas proposal, and have made a variety of alternative proposals for off-system delivery services and rates. Interveners want assurance that OSD is not subsidized by on-system customers and does not impact their rates, and one party asserts that the CPUC should reject the SoCalGas proposal.

The CPUC expects to issue its decision in this proceeding in 2010.

Firm Access Rights Review - A.10-03-028

As authorized by the CPUC, SoCalGas allows customers to obtain and pay for "firm access rights" (FAR). These rights ensure customers, including the company's core procurement department acting on behalf of core customers, that their supplies will be delivered onto the SoCalGas transmission system at various receipt points with a high degree of reliability. The framework is somewhat similar to the PG&E GT&S (or "Gas Accord") framework discussed above. The firm access rights framework was implemented on October 1, 2008.

In the decision that approved the FAR system, the CPUC required a review of the system's implementation to make sure that it was operating as intended. This review was to be conducted beginning 18 months after implementation. With A.10-03-028, SoCalGas filed its FAR review application on March 29, 2010.

Although the scope of the proceeding has not yet been officially set, the CPUC expects as part of this proceeding to determine the proper revenue requirement associated with firm access rights and to set rates accordingly.

At this time, it is unclear whether the CPUC would reach a decision in this proceeding in 2010 or whether a decision would be reached in 2011.

SoCalGas and SDG&E 2012 General Rate Case

In D.08-07-046, the last SoCalGas/SDG&E GRC decision, the CPUC ordered SoCalGas and SDG&E to file another GRC for the forecast year of 2012. Thus, the CPUC expects that SoCalGas and SDG&E will file another GRC application toward the end of 2010 or possibly in early 2011. The CPUC will determine the revenue requirement in that proceeding for SoCalGas' gas system (excluding the cost of gas) and for SDG&E's gas and electric system (excluding the cost of gas and electricity and electric transmission).The CPUC likely will not reach a decision in this proceeding until late 2011.

Gas Public Purpose Program (PPP) Surcharge

The state's natural gas utilities collect funds from core and non-EG noncore customers for gas related energy efficiency programs, low-income programs including the CARE subsidy, and for the California Energy Commission's (CEC) natural gas research and development (R&D) program. The annual budget of these public purpose programs are set in various recurring program-related Commission proceedings. In 2009, the costs of the gas related PPPs was about $531 million. These costs are collected by the utilities through the gas PPP surcharge appearing on customer gas bills. Gas PPP costs have increased by 20% since 2006, due to increases in energy efficiency and gas R&D costs.

Public purpose programs benefit customers in a variety of ways. The Energy Action Plan lists energy conservation and efficiency as the first undertaking to help ensure that Californians receive safe, reliable utility service at least cost. While the energy efficiency program costs are borne by customers, the program should lower customer utility bills as they reduce their energy consumption. The low-income programs (CARE and LIEE) serve to lower the gas bills of the utilities' financially disadvantaged customers. The Gas R&D program is administered by the CEC with the goal of the funding projects that will benefit the public at-large. Such projects may be related to energy efficiency, renewable energy production, and environmental enhancements. Energy efficiency costs and low-income costs are discussed elsewhere in this report.

CPUC Advocacy for California Interests at the FERC

The CPUC represents California gas interests at FERC Gas proceedings. In the last few years, CPUC intervention at the FERC has been primarily on interstate pipeline general rate cases.

California obtains more than 85% of its natural gas supply via pipelines from out-of-state, chiefly from natural gas basins in Canada, the Rocky Mountain states, and the southwest states of New Mexico and Texas. The main interstate pipeline companies supplying natural gas to California are El Paso Natural Gas (from New Mexico and Texas gas basins), Transwestern (from New Mexico and Texas gas basins), GTN (from Canadian gas basins), and Kern River (from Rocky Mountain gas basins). Interstate pipelines are regulated by the FERC and are thus outside of California's direct regulatory control. FERC oversees general rate cases (GRCs) for interstate pipeline companies.

California gas consumers, including public utilities such as PG&E and Southern California Gas Company, typically negotiate short-term and long-term (i.e., multi-year) natural gas capacity contracts for capacity rights on the pipelines operated by the aforementioned interstate pipelines companies.

In the next 12 months, the CPUC will continue to represent California interests in the GRC for El Paso Natural Gas (EPNG). EPNG is the single largest interstate natural gas pipeline to California. California shippers typically hold about half the capacity on EPNG, with east-of-California customers (chiefly in Arizona) holding the other half. California utilities directly hold capacity rights on El Paso for core customer supply requirements. This GRC has been ongoing since 2009.

On March 11, 2010, EPNG customers submitted a settlement to FERC for reservation rates that would establish California maximum firm reservation rates. Several issues have been carved out of the settlement for separate litigation tentatively scheduled to commence in May 2010.

EPNG may submit a new GRC shortly after the current one concludes. It is also possible that within the next 12 months another interstate pipeline company that makes significant deliveries to California, Transwestern, will file a GRC at the FERC. If it does, the CPUC fully expects to participate in that GRC as well.

Appendix:

Utility Reports on Recommended Measures to Limit Costs and Rate Increases

A. Pacific Gas and Electric Company

B. Southern California Edison

C. Southern California Gas Company

D. San Diego Gas and Electric Company

Utility Studies And Reports On Recommended Measures To Limit Costs And Rate Increases

A. *Pacific Gas and Electric Company*

B. *Southern California Edison*

C. *Southern California Gas Company*

D. *San Diego Gas and Electric Company*

A. *Pacific Gas and Electric Company*

SEE ATTACHED PDF DOCUMENT

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March 19, 2010

Ms. Julie Fitch
Director
Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: SB 695 2010 Compliance Report - Pacific Gas & Electric Co.

Dear Ms. Fitch:

Attached, please find PG&E's final version of the 2010 SB 695 Section 8 (PUC Section 748) compliance report. We hope you will find it useful in compiling the Energy Division's report to the Legislature.

Sincerely,

Amrit Singh

cc: (via e-mail)
Steve Roscow, Energy Division

Attachment

SB 695 Report To California Public Utility Commission Energy Division
Reporting Entity: Pacific Gas and Electric Company
Year: 2010

I. Introduction

Pursuant to the requirements of Public Utilities Code section 748(b), Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide its initial study and report to the California Public Utilities Commission (CPUC or Commission) on measures PG&E recommends to be undertaken to limit costs and rate increases. This report provides data and forecasts related to PG&E's gas and electric revenue requirements and rates, and is structured to include PG&E's overall rate policies at PG&E; a description of PG&E's current revenue requirement components, a discussion of PG&E's rate components, PG&E's management of its rate components, and a schedule of PG&E's 2010 rate filings (as an appendix).

Last summer PG&E heard from many electricity customers that electricity rates for customers who use the most energy were just too high. In these tough economic times, PG&E knows how important it is for our customers to keep monthly costs to a minimum. PG&E understands that electricity is a fundamental need and PG&E is also working hard to help our customers save.

Last month, PG&E filed a number of actions with the California Public Utilities Commission asking for rate relief for customers in two forms. First, PG&E has requested an overall rate reduction to take effect on June 1. Second, PG&E has asked the CPUC to change the tiered residential rate structure in a way that reduces the costs for our highest use residential customers.

Current state law mandates that electric utilities in California must charge more per unit of electricity as a household's use increases. Under the tiered-rate system, electricity use is divided into tiers, with higher prices for each higher level of use. In 2001, the Legislature and the CPUC essentially capped the lowest tiers from increases -- tiers 1 and 2 -- and those lower tier rates remained largely unchanged during 2001-2009. That means rate increases during that period fell almost exclusively into the higher tiers. This amplified the impact of rate increases on people who use more electricity in every part of our service area and, in turn, increased the cost of their electricity bills.

We are committed to helping limit or reduce costs to our customers, and it is our hope that through the recommendations in this report, PG&E can help customers during these tough times. PG&E's request to restructure rate tiers will bring our residential rates more closely into alignment with other utilities in the state. Our proposal to reset the residential rate tiers distributes electricity costs more equitably among all our customers. PG&E hopes this eliminates some of the "sticker shock" that can occur when a customer's usage crosses into the top rate tier, especially during peak summer and winter months.

In order to manage utility costs and rate increases, PG&E recommends modifications to certain aspects of CPUC energy procurement requirements, market structure, and statewide mandates. However, certain components of gas and electric rates are largely beyond the direct control of utilities, and instead result from market factors or policy mandates. Among these are the market price of natural gas used to supply retail customers and power generators; expenditures on public purpose programs mandated by law; the rate of uncollectible costs attributable to economic conditions faced by customers; the overall need for statewide infrastructure investment; the costs of Renewable Portfolio Standard (RPS) compliance; and the costs for compliance with greenhouse gas (GHG) emissions regulations and goals.

In addition, within the framework for the allocation of costs and rate design mandated by the Legislature and the CPUC, PG&E seeks to equitably allocate costs among its customers based on energy usage and category of customer. Crafting equitable allocation rules for revenue requirements across customer classes also poses challenges, largely due to rate designs mandated by law and the need to collect revenues to fund programs to benefit a specific set of customers, but are paid for by non-participating customers.

PG&E believes that the measures and actions in this report can have a beneficial near-term impact to its total cost of delivering safe, reliable, and cost-effective gas and electric services to its customers in California.

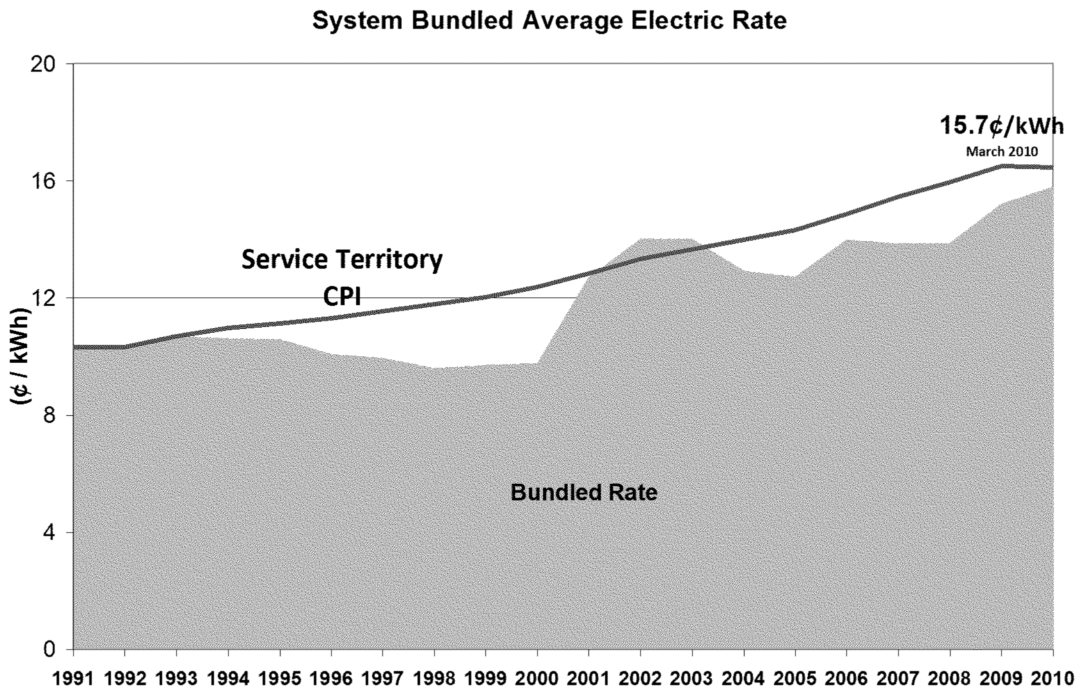
II. Overall Rate Policy

PG&E strives to provide its customers with reasonable rates for gas and electric service. PG&E's overall rate policy is to fully recover the costs of efficiently serving its customers, while considering cost-based pricing, equity within and among customer classes, and public policy objectives.

PG&E understands that its customers value transparency and stability. Therefore, PG&E seeks to minimize the impact of rate adjustments made throughout the year. Generally, PG&E requests electric rate changes two to three times per calendar year (January and March and October). For gas rate changes, PG&E files monthly advice letter filings to change the gas commodity rate and seeks an annual gas transportation and public purpose program rate change. In addition, PG&E submits various filings to the CPUC throughout the year in response to specific Commission directives or changes to the utility business, to ensure that PG&E provides reliable and cost effective service to its customers.

PG&E also undertakes efforts to manage the timing of revenue changes and subsequent rate changes. Over the past twenty years, PG&E has been successful at managing electric customer rate increases. As illustrated in Figure 1, PG&E's system bundled average electric rate over the last twenty years has increased at a lower rate than the service territory's consumer price index growth (CPI) (See Figure 1). This modest rate growth over time has resulted from careful utility cost containment and a general increase in sales (which moderates the upward pressure of revenue requirement growth). From time to time, PG&E also manages revenue collection through balancing accounts - tempering rate swings driven by differences in sales used to set rates and actual demands experienced. For example, in 2009, PG&E minimized swings in customer rates and bills via adjusting the timing of certain California Department of Water Resources-related payments and implementing a one-time Energy Resource Recovery Account bill credit to electric customers from balancing account overcollections. Similarly, to decrease pressure on customer bills during 2010, PG&E has requested approval to accelerate credits of balancing account over-collections and defer collection of certain approved revenue requirements.

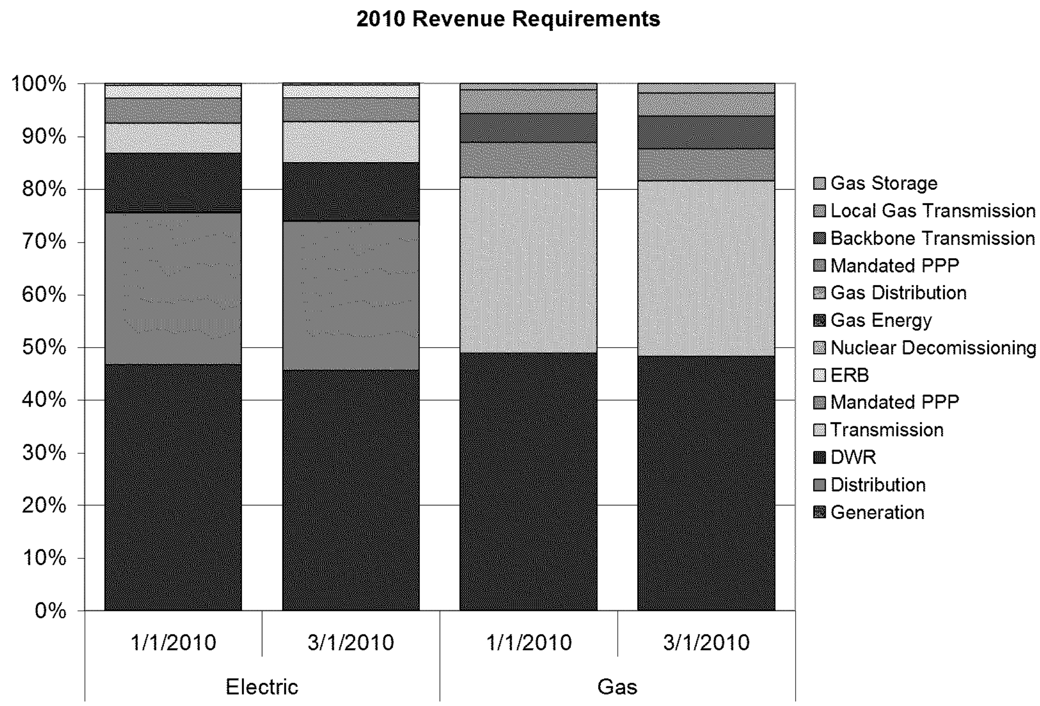
Figure 1. Historic Service Territory CPI vs. System Bundled Average Electric Rate. CPI provided by Economy.com



III. <u>Description of Revenue Requirement Components (Gas and Electric)</u>

This section summarizes the major components of PG&E's gas and electric revenue requirements (RRQ) and how changes in those components are forecast to affect overall rates. For example, Energy/Generation includes purchased power costs, utility-owned generation, and pension revenue requirements linked to generation, among other items. Relative ranges for each RRQ category as a percent of total authorized 2009 RRQ, and analogous forecast trends for 2010, are provided for each RRQ section. A summary is provided in Figure 2 below. Percentage ranges are calculated by comparing the category's revenue requirement to the total authorized revenue requirement during the course of the year (e.g. Authorized 2009 Electric Transmission RRQ divided by Total Authorized 2009 Electric RRQ). This calculation provides a means to discuss the relative magnitude of the major revenue requirement categories and the trend over time. Note that the focus is not on specific filings brought forth to the CPUC, but rather categories of revenue requirements that could have a potential impact on future rates.

Figure 2. High Level Breakdown of PG&E Revenue Requirements in 2010



Natural Gas

Natural gas revenue requirements are commonly grouped into the following six major categories: (1) Energy, (2) Distribution, (3) Public Purpose Programs/Mandated Programs, (4) Backbone Transmission, (5) Local Transmission, and (6) Gas Storage. For reference, an excerpt from the Advice 3060-G-A Annual Gas True-Up filing on December 22, 2009 is provided as Table 1 in the Appendix. The following statements reflect PG&E's expectations as of February 1, 2010, and may change throughout the course of the coming year due to various internal and external factors.

1) <u>Energy-related gas revenue requirements</u> represent approximately 44 percent to 55 percent of the total forecast gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to trend upward, consistent with the market price of natural gas. For 2009, the energy revenue requirement represented about 46 percent of the total authorized gas revenue requirements.

2) <u>Distribution-related gas revenue requirements</u> constitute about 30 percent to 38 percent of the total forecast gas revenue requirements in the upcoming 12 months, and are expected to trend upward primarily due to additional maintenance and replacement work and system reliability-driven projects. For 2009, the distribution revenue requirement constituted about 36 percent of the total authorized gas revenue requirements.

3) <u>Public Purpose Programs or Mandated-related gas revenue requirements</u>, including California Alternate Rates for Energy (CARE) Discount and Self-Generation Incentive

Program, and Energy Efficiency, represent approximately 6 percent to 7 percent of the total forecast gas revenue requirements in 2010. The revenue requirements are expected to trend slightly upward in the upcoming 12 months, mainly due to increased total discounts provided to customers on CARE. The increase in forecast CARE discounts is driven by the cost of gas and CARE participation. For 2009, mandated programs contributed about 7 percent of the total authorized gas revenue requirements.

4) Forecasted backbone transmission-related gas revenue requirements comprise approximately 5 percent to 7 percent of the total forecast revenue requirement in the coming year, and are generally expected to trend slightly upward in 2010. Increases in 2011 and 2012 are driven by replacement of aging facilities and retrofits/replacements for environmental regulations. For 2009, backbone transmission revenue requirements constituted about 7 percent of the total authorized gas revenue requirements.

5) Local transmission-related gas revenue requirements generally contribute 4 percent to 5 percent of PG&E's total forecast gas revenue requirement in the upcoming 12 months primarily due to capital additions for reinforcement projects, as well as operating and maintenance costs, particularly for integrity management. For 2009, local transmission represented approximately 5 percent of the total authorized gas revenue requirements.

6) Forecasted gas storage-related revenue requirements comprise approximately 1 percent to 2 percent of the total forecast revenue requirement in the coming year and are generally expected to trend upward. The revenue requirements are driven by new infrastructure and upgrades to existing facilities to ensure reliable, safe services, and access to diverse gas supplies. For 2009, gas storage revenue requirements contributed about 2 percent of the total gas revenue requirements.

Electric

Electric revenue requirements are commonly grouped into the following seven major categories: (1) Energy/Generation, (2) Distribution, (3) Department of Water Resources (DWR), (4) Transmission, (5) Public Purpose Programs, (6) Nuclear Decommissioning, and (7) Energy Revenue Bonds (ERB). For reference, excerpts from the December 31, 2009 Annual Electric True-Up filing are provided as Table 2 in the Appendix. The following statements reflect PG&E’s expectations as of February 1, 2010, and may change throughout the course of the coming year.

1) Energy/Generation-related electric revenue requirements constitute approximately 48 percent to 52 percent of the total forecast revenue requirement in the coming 12 months. Of that, energy procurement costs represent roughly 67 percent of PG&E’s generation revenue requirement in 2010. In contrast, utility-owned generation represents 22 percent of the generation revenue requirement. CTC (Competition Transition Charge) represents 2 percent to 3 percent of the total forecast revenue requirement in 2010 and remains relatively flat through the year. During 2009, generation revenue requirements comprised 50 percent to 51 percent of PG&E’s total authorized revenue requirement, and 68 percent of that was attributable to energy

procurement. The CTC revenue requirement was 5 percent during 2009, due largely to undercollections resulting from differences in actual sales versus forecast sales. The year-over-year change in total generation-related revenue requirements reflects new utility-owned generation (e.g. Colusa) becoming operational during the 2010, projected reductions in purchased power, as well as attrition adjustments for inflation.

2) Distribution-related electric revenue requirements, including the California Solar Initiative and the SmartMeter™ program, comprise approximately 25 percent to 29 percent of the total and trend upward in the coming year. For 2009, Distribution revenue requirements represented 27 percent to 29 percent of the total authorized revenue requirement. The increase year-over-year is primarily due to balancing account adjustments made to compensate for differences in sales used to set rates and the actual sales levels experienced, which were lower than forecast.

3) The DWR-related electric revenue requirements (including DWR bond) comprise 11 percent of PG&E's forecast 2010 revenue requirement and are expected to decline on January 1, 2011, due to the expiration of DWR contracts and timing of indifference (transfer) payments between California's investor-owned utilities. During 2009, DWR-associated revenue requirements ranged from 9 percent to 13 percent of the total authorized revenue requirement. It should be noted that for ratemaking purposes, DWR is treated as a Generation cost.

4) Transmission-related electric revenue requirements contribute 6 percent to 8 percent of the total forecast revenue requirement in the coming year. Through 2009, transmission revenue requirements accounted for approximately 5 percent to 6 percent of the authorized total. Investments undertaken by other California Utilities and PG&E both contribute to the transmission revenue requirement growth over 2009. Transmission revenue requirements are generally expected to increase over time due to electric transmission investments undertaken by PG&E and the other California utilities to comply with North American Electric Reliability Corporation (NERC) reliability requirements, upgrades to existing assets, expansion of new service, and providing access to RPS-eligible power.

5) Public Purpose Program-related electric revenue requirements comprise 5 percent of PG&E's total forecast revenue requirement during 2010. In comparison, PPP represented less than 2 percent of the total during 2009. Growth in PPP revenue requirements from 2009 to 2010 is tied to inflation of base costs as well as the expansion of key policy programs such as CARE and Energy Efficiency 2010 -2012 Programs which incorporate key elements of the Commission's Energy Efficiency Long Term Strategic Plan. In particular, the CARE shortfall projected for 2010 reflects the unexpected increase in actual customer discounts provided versus assumptions made when setting the CARE surcharge. And, the nearly $268 million energy efficiency refund provided in 2009 which does not carry through to 2010 also causes a major shift in revenue requirements year over year.

6) Nuclear Decommissioning-related electric revenue requirements represented less than 1 percent of PG&E's total authorized revenue requirement during 2009. That level is forecast to remain constant in 2010.

7) Energy Recovery Bond-related electric revenue requirements represent roughly 2.5 percent of PG&E's forecast revenue requirement in 2010 and will come to the end of their life during 2011. During 2009, ERB comprised between 1 percent and 2 percent of the total revenue requirement.

IV. Description of Rate Components (Gas and Electric)

Revenue requirements (RRQs) discussed in the previous section directly align with rate components. At the highest level, gas and electric rates can be described as revenue requirements divided by sales. Therefore, both revenue requirement changes and demand variations impact the actual rates for gas and electric service. RRQs expected to increase in the coming twelve months will tend to drive rates up. For those RRQs which trend down, rates similarly will be reduced. The rate pressures created by RRQs are modulated by differences in actual sales versus prior estimates (used to set rates). Adjustments in the allocation of revenue requirement across customer classes and rate tiers also impact the rates experienced by individual customers. Table 1 below provides a summary.

Table 1. Summary of Rate Components for 2010

COMPONENT	Electric 2010		Gas 2010	
	RRQ $M %	Range RRQ	$M	% Range
Energy / Generation	$6,544	48-52	$1,832	44-55
Distribution	$3,638	28-32	$1,277	30-38
Transmission / Backbone Transmission	$720	6-8	$241	5-7
Local Transmission (Gas)		N/A	$164	4-5
Public Purpose Programs / Mandated Programs	$762	5	$188[2]	6-7
Gas Storage		N/A	$52	1-2
Nuclear Decommissioning	$26	0-1	N/A	
Energy Recovery Bond	$316	2.5		N/A
Total Authorized Revenue Requirement[1]	$12,600		$3,754	

1. As of February 1, 2010. Gas applies new 2010 BCAP core procurement volumes. Values are approximated to the nearest million.
2. Reflects CARE shortfall of approximately $65M.

Published Load/Demand Forecasts

Customer sales volatility over time directly impacts the rates experienced by gas and electric customers. PG&E reviews load forecasts for its service territory on a regular basis to inform rate change filings taken to the Commission. Historically, aggregate customer sales increased at a pace which largely offset annual increases to revenue requirements. However, in recent years (2008 and 2009) as a result of the economic recession, the softening of sales growth means each customer has shouldered a larger portion of revenue requirement increases. The following section discusses the forecast trends for Gas and Electric loads during 2010.

Gas

As described in the Electric subsection below, PG&E's service area economy is expected to remain weak through 2010. This will impact both electricity demand and gas throughput. PG&E's forecast projects 2010 gas sales for all three major gas customer classes - residential, commercial, and industrial - to show modest declines in usage this year. Looking further out, residential and commercial demand are expected to change very little from 2010 to 2015.

The residential gas demand forecast incorporates real residential rates, the number of households in PG&E's service territory, heating degree days and the percentage of households built after 1978, or when title 24 multifamily energy efficiency standards went into effect. Unlike electricity, which has innumerable residential uses, the main residential use for gas is space and water heating, therefore requiring customer growth to drive usage growth. With little customer growth and unemployment remaining high, residential demand is projected to be essentially flat over 2009 totals (-0.1 percent). Since space heating is the principle use of gas in the commercial sector (as it is for residential use), growth is dependent on the level of business activity within the sector. With commercial vacancy rates already high, and with the potential for them to climb even higher in 2010, gas usage in this sector is projected to decline by nearly 2 percent this year. The soft economy will also drive industrial sales lower in 2010 by 1.4 percent.

Conversely, demand for gas used in Electric Generation is expected to be higher by 10 percent in 2010 than 2009. Many factors drive the volatility in gas demanded for electric generation, including the economy, gas prices, hydroelectric generation capacity, new generation facilities coming online, nuclear generating capacity, and others.

Electric

For 2010, economic growth within PG&E's service territory, as forecast by Economy.com, is projected to remain soft. The economy will continue to lose jobs, and household income will continue to decline. With this outlook as a backdrop, PG&E's forecast projects electric sales for 2010 declining at 0.6 percent relative to 2009 observed sales. If the economic rebound gains traction in 2011, PG&E expects to see electric sales growth turn positive, increasing by 1.1 percent. Consistent with the notion that 2010 represents a "rocky bottom" to this recession, PG&E's sales projections for 2010 are mixed.

Electric customer (billings) growth has also been dramatically impacted by the recession. For 2010, customer growth will exhibit the same sluggishness as the economy at large. PG&E's forecast shows an addition of about 25,000 customers in 2010, which pales next to the 70,000-80,000 PG&E regularly observed annually during the middle of the last decade. By 2011, a recovering economy should yield stronger customer growth.

Among the four major electric customer classes (residential, agricultural, industrial, commercial) two are projected to show declining sales, one is projected to be flat, and one is projected to show an increase compared to 2009. With household incomes still declining and job security tenuous, residential usage is projected to decline by 1.3 percent in 2010. Agricultural sales (primarily groundwater pumping) have grown substantially during the last 3 years in response to below normal rainfall levels. With assumed normal rainfall built into the forecast, however, agricultural demand is projected to decline in 2010 (-5.5 percent), but remain at a high level of usage by historical standards. Industrial sales, after declining a dramatic 9 percent in 2009, will essentially remain flat in 2010 (-0.2 percent). The commercial sector is the one sector projected to show any growth at all, and even this will be meager at just 0.6 percent. Increased consumer spending and higher service sector output are the main drivers here, but both are on shaky footing and any erosion of this sector's growth could turn commercial sales negative as well.

V. Management of Key Rate Components

PG&E is committed to controlling costs while providing safe and reliable gas and electric service to its customers. However, there are many key drivers that affect customer rates which fall outside of PG&E's control. Among these are the market price of natural gas, actual retail sales volumes, uncollectable accounts, weather, interest rates, and permitting process delays. Despite these factors, PG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

VI. 2010 CPUC Filing Outlook

Attached for your reference is Appendix A, which reflects key filings data provided previously to the Energy Division (December 2009). The table has been modified per the currently anticipated filing schedule for 2010, and now also reflects the revenue requirement or rate components (see Section III) that are primarily affected by each filing. This is not an exhaustive list of PG&E's 2010 filings; rather it incorporates planned regulatory filings which are known at this time to have a rate impact for gas or electric customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized or settled are subject to change via the normal regulatory approval processes of the CPUC and other regulatory agencies.

VII. Recommendations to the CPUC and Legislature

In this section, PG&E provides its recommendations for measures that can be undertaken in the next 12 months to limit utility cost and rate increases, in addition to the recommendations in the Introduction. These recommendations address factors related to the economy, state and federal energy policy, and regulatory policies and orders, which PG&E believes significantly impact utility costs and resulting customer rates in the near to medium-term.

PG&E is committed to meeting California's energy and environmental goals for reducing greenhouse gases (GHG); enhancing its infrastructure and improving its operations. However, PG&E believes environmental goals should not be met *at any cost* – care should be taken to address rate impacts of choices as GHG emissions goals are defined. In the coming year, PG&E recommends that several key State policies and procedures could be modified or clarified to support more effective, efficient and beneficial deployment of revenues collected from PG&E customers. PG&E believes that adoption of these recommendations at the State level will help to alleviate significant upwards cost pressures and ultimately reduce customer rates for gas and electric service.

1. Gas procurement policies

PG&E procures natural gas for direct consumption by a large portion of residential and small business customers (commonly referred to as core procurement gas customers) and to supply PG&E-owned as well as third-party owned electric generation facilities which supply electricity to PG&E's bundled electric customers. To minimize costs of natural gas procurement and to meet reliability targets, PG&E purchases from various supply sources and also negotiates long-term contracts on a variety of transportation and storage systems. PG&E also employs financial hedging instruments to maintain cost stability and to limit the impact of spikes in natural gas prices on customer bills.

PG&E supports the implementation of initiatives that provide PG&E and its customers with expanded access to diverse supply regions for natural gas, such as the long-term transportation contracts on the proposed Ruby Pipeline. These transportation contracts, which were approved by the CPUC in 2008 and executed by the company in 2009, will provide PG&E customers with direct access to natural gas from the Rockies region beginning in 2011. PG&E also supports continued State energy policies and initiatives to expand and evaluate new options for natural gas supply, transportation and storage in order to effectively manage the costs of procuring natural gas for PG&E's customers.

2. Retail Electricity Dynamic Pricing

The CPUC has initiated an ambitious policy toward implementation of dynamic retail electricity pricing in PG&E's service territory. Dynamic pricing is defined as pricing that reflects real time system costs and therefore requires the functionality of the newly installed SmartMeter™ infrastructure (which provides hourly usage data). Dynamic pricing is expected to have a number of benefits including: lowering costs by more closely aligning retail rates and wholesale system conditions, thereby promoting economically efficient decision making; improving system reliability by providing an incentive to lower usage when the supply and demand balance is strained or in times of system emergencies; reducing greenhouse gas emissions by reducing the need to operate inefficient resources; and finally, providing a key building block of the smarter energy grid.

In 2010, PG&E will begin to default its largest customers to a form of dynamic pricing called Peak Day Pricing, which provides specific rates for peak energy days, and lower rates during other days. Though customers will be able to opt out, with the availability of first year bill protection, participation is expected to be much higher than it would be otherwise. In

2011, this initiative extends to all non-residential commercial mass market customers (about 500,000 customers), who will lose the option to take service on rates that are not time-differentiated.

In addition, changes in law enacted in SB 695 would afford the opportunity to default all residential customers (about 4.5 million customers) to "Peak Day Pricing," (a form of dynamic pricing) as early as 2013. PG&E recommends that any such effort be undertaken carefully and only after customers, utilities, and regulators can evaluate to the rate impacts of defaulting residential customers onto these new rates. PG&E, customers and the Commission can learn from the efforts to default commercial mass market customers in 2011. Further, PG&E recommends that the default options should be studied carefully to ensure the best approaches and options are determined before any such program is implemented.

Finally, closely following the implementation of Peak Day Pricing, all customers will be offered the option of Real Time Pricing, which charges customers for energy indexed to the California Independent System Operator's day-ahead market prices. Over the next 12 months, the CPUC, other energy policymakers, customers and PG&E need to proactively work together so that the full benefits of dynamic pricing can be realized without excessive cost or unanticipated impacts on customers.

3. Other Electric Rate Design Policies

PG&E and the Commission have endorsed rate policies based on cost of service. PG&E believes that such policies are appropriate and should continue. Such policies are sustainable because they encourage efficient decision making by customers. At times, departing from cost-based rates can be appropriate if justified in order to accomplish other public policy objectives. Such objectives include energy efficiency, benefits provided to low income customers, mitigation of rate changes from year to year, promotion of renewable generation, GHG emissions reductions, and encouraging innovation and developing technologies.

However, each departure from cost-based rates carries with it the risk that one set of customers—the non-benefiting customers—will be paying higher than cost-based rates to subsidize another set of customers—the benefiting customers. Thus, each departure from cost-based rates needs to be carefully evaluated to determine whether the rate increases to non-benefiting customers are reasonable in light of the overall benefits to benefiting customers and society at large. While perhaps beneficial from a policy perspective, programs that support these ends (such as net metering and standby waivers) can result in costs being shifted to other customers. When a customer reduces their own contribution to cost of service to below avoided costs, the difference shortfall is paid by other customers. Because PG&E's current rate structure recovers a portion of fixed costs via a variable rate, any program that reduces participants' costs can create upward pressure on rates for other customers.

In the next 12 months, PG&E recommends that the California Legislature and other energy policymakers carefully evaluate and re-examine several examples of non-cost-based ratemaking that are significantly impacting the level of current rates and costs to customers, including 1) the spread in residential tiered rates, and 2) incentives and costs associated with distributed generation.

The first and most immediate area of concern that should be evaluated over the next 12 months is residential electric rate design, where a 5 "tier" rate structure is employed. This structure, first put in place during the energy crisis ten years ago, has grown to have a punitive effect on customers, and does not reflect the true cost of service. The effects of this structure were most recently seen in customers' adverse reaction to bills in the Central Valley during the summer of 2009. One significant driver of these complaints was the rate change from summer of 2008 to summer of 2009, when the Tier 5 rate increased from 36 to 44 cents per kWh. Without modification, rates projected for the summer of 2010 are expected to be close to 50 cents per kWh. PG&E has asked for expedited treatment of several initiatives designed to lower upper tier rates for the summer of 2010, and respectfully requests the Commission's support to make these changes. While legislation was recently passed to allow limited increases to Tier 1 and Tier 2 rates, the Commission and Legislature should be mindful that this approach alone will not prevent upper Tier rates from continuing to be punitive in the longer term. PG&E recommends the spread in tiered rates be monitored over time and legislative change be sought to more fully address this issue.

The second area of concern that should be evaluated is the non-cost-based subsidies by retail customers to owners or operators of distributed electricity generation systems. The California Legislature has required policies such as retail net metering; above-market payments for generation exports to the grid; incentive programs; and exemptions from standby related charges. As a result, rates for non-participating customers have increased, resulting in rates which do not reflect true cost-of-service. Subsidies that do not reflect true economics do not promote efficient deployment of resources. Increased penetration of distributed generation beyond today's relatively modest levels will call for a deliberate consideration of rate design changes to moderate rate increases to non-participating customers. Ultimately, these cost shifts may not be sustainable, reasonable or fair. Therefore, PG&E recommends policymakers explore and adopt alternative ways to provide transparency and fairly allocate the transmission, distribution and above-market energy costs associated with distributed generation across all system customers.

4. Increasing Renewable and Alternative Energy and Reducing Greenhouse Gas Emissions at Reasonable Cost

Assembly Bill (AB) 32 requires the gradual reduction of greenhouse gas (GHG) emissions in California to 1990 levels by 2020 on a schedule beginning in 2012. In December 2008, the California Air Resources Board (CARB) adopted a scoping plan that contains recommendations for achieving the 2020 target which include developing a multi-sector cap-and-trade program, achieving a 33 percent renewable portfolio standard (RPS) by 2020, increasing energy efficiency, and expanding the use of combined heat and power facilities. In addition, the California Legislature, Governor and CPUC are all considering separate legislation, policies and programs that would increase renewable electricity to 33% as part of the renewable portfolio standard as well as increase the availability of "combined heat and power" generating facilities.

As state policymakers move forward with implementation of these environmental and energy goals, PG&E continues to stress the importance of managing costs to California consumers and businesses by pursuing cost-effective reduction strategies and cost containment provisions. The ultimate success of such efforts will depend largely on key design issues for the cap-and-trade program, -- such as the number of emission allowances allocated to the Utility for the benefit of our customers, the development of robust cost containment tools for the price of emission allowances, use of emission offsets, and the ability to link to other cap-and-trade programs -- in addition to renewable and energy efficiency issues as described in this section.

5. Once-Through Cooling Policy for Existing Powerplants

Since 2006, the State Water Resources Control Board (SWRCB) has issued four preliminary proposals outlining the reduction of once-through cooling (OTC) technology in generation facilities. There are currently 18 California power plants that use OTC, including PG&E's Diablo Canyon facility (Humboldt goes off-line in 2010 when the new facility begins operations). The SWRCB is now considering the adoption of a policy to phase out the use of once-through cooling at electric generation facilities. In particular, the SWRCB has proposed that these plants can either be retrofit or re-powered with another cooling technology or shut down completely. Compliance deadlines under the proposal range from 2011 to 2024 with compliance deadlines staggered in a manner to help assure system reliability.

The California utilities have procurement contracts with a number of entities that employ once-through cooling, and also operate two nuclear power plants which rely on once-through cooling. A change in the state's policy to disallow the use of once-through cooling could result in billions of dollars in power plant retrofitting costs to utility customers. PG&E has submitted an engineering study to the SWRCB that indicates retrofitting costs for Diablo Canyon alone could amount to $4.5 billion. PG&E continues to advocate for an orderly transition away from OTC through planned repowering, replacement or retirement of the state's fossil plants, and for cost-benefit analysis at the nuclear facilities to determine whether retrofit is appropriate given the substantial costs and collateral environmental impact of moving to closed-cycle cooling in terms of GHG emissions and other air quality impacts.

6. Streamlining and Expediting Permitting and Approvals of New Transmission and Distribution Facilities

Studies prepared by the CPUC, California's Renewable Energy Transmission Initiative (RETI) and the California Independent System Operator (CAISO) have all identified the need for substantial investment in electric transmission to achieve the state's RPS and GHG emission reduction targets. Planning, siting and constructing electric transmission infrastructure requires navigating a complex and costly maze of regulations and requirements. In order to limit the costs of delay and "red tape" being imposed on utility customers for these essential project, the Energy Commission, CPUC, California Legislature and involved state agencies should immediately speed these processes and reduce the overall cost of developing the infrastructure necessary to achieve California's energy policy goals.

While not as high profile as the electric transmission expansion studies, upgrades will be needed to the electric distribution system to support higher penetration of distributed generation and electric vehicles. The underlying generation projects and the distribution system upgrades will also require permitting by various federal, state and local agencies. Existing planning and siting approval processes require between seven and ten years to complete an electric transmission project. Achieving the targeted RPS and GHG policy goals will be impossible if the current processes are not improved. California policymakers and various permitting agencies should also immediately speed the processes of developing these projects.

Tables and Appendices

Table 1. Excerpt from Advice 3060-G-A Annual Gas True-Up filing for Rates Effective January 1, 2010.

Pacific Gas and Electric Company
San Francisco, California
U 39

	Revised	*Cal. P.U.C. Sheet No.*	27953-G
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	27393-G

GAS PRELIMINARY STATEMENT PART C Sheet 2
GAS ACCOUNTING TERMS & DEFINITIONS

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

Description	Amount ($000) Core	Noncore	Unbundled	Core Procurement	Total
GRC BASE REVENUES (Incl. F&U) (1):					
Authorized GRC Distribution Base Revenue					1,139,444 (I)
Less: Other Operating Revenue					(26,023)
Authorized GRC Distribution Revenues in Rates	1,076,931 (I)	36,490 (I)			1,113,421 (I)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:					
G-10 Procurement-Related Employee Discount	(2,624)(R)				(2,624)(R)
G-10 Procurement Discount Allocation	1,103 (R)	1,521 (R)			2,624 (R)
Less: Front Counter Closures	(355)				(355)
Core Brokerage Fee Credit	(9,581)				(9,581)
GRC Distribution Base Revenue with Adj. and Credits	1,065,474 (I)	38,011 (I)			1,103,485 (I)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (2):					
Transportation Balancing Accounts	137,518 (I)	11,908 (I)			149,426 (I)
Self-Generation Incentive Program Revenue Requirement	2,586	3,534			6,120
CPUC Fee	2,076	2,718			4,794
ClimateSmart	0 (R)	0 (R)			0 (R)
SmartMeter™ Project	45,997 (I)				45,997 (I)
Winter Gas Savings Plan (WGSP) – Transportation	2,274 (I)				2,274 (I)
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,179 (I)	239 (I)			2,418 (I)
CARE Discount included in PPP Funding Requirement	(109,433)(R)				(109,433)(R)
CARE Discount not included in PPP Surcharge Rates	0				0
Transportation Forecast Period Costs & Balancing Account Balances	83,197 (I)	18,399 (I)			101,596 (I)
GAS ACCORD REVENUE REQUIREMENT (Incl. F&U) (3):					
Local Transmission	114,854 (I)	49,146 (I)			164,000 (I)
Customer Access Charge – Transmission		5,174			5,174
Storage	42,093		7,499		49,592
Carrying Cost on Noncycled Storage Gas	1,757		251		2,008
Backbone Transmission/L-401	80,394 (R)		160,593 (R)		240,987 (R)
Gas Accord Revenue Requirement	239,098 (I)	54,320 (I)	168,343 (R)		461,761 (I)

(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2007, in General Rate Case D.07-03-044, and $22M for Attrition as approved in AL 2877-G, 2954-G, and AL 3050-G. The GRC distribution base revenue is allocated to core and noncore customers in Cost Allocation Proceedings, as shown in Part C.3.a. (T)

(2) The total 2009 SGIP revenue requirement (RRQ) was approved in D.09-12-047. (T)
Per D.06-05-019, SGIP costs were removed from wholesale gas rates on July 1, 2006. The Climate Protection Tariff RRQ for 2009 was approved in D.06-12-032. On April 27, 2009, PG&E filed an Application requesting a 2-year extension of the ClimateSmart program. PG&E seeks no additional customer funding. The SmartMeter™ Project RRQ was approved in D.06-07-027 and AL 2752-G/G-A. The Energy Division approved PG&E's AL 3039-G for the WGSP costs, which are recovered in commercial customers" rates beginning January 1, 2010. (T)

(3) The Gas Accord IV RRQ effective January 1, 2009, was adopted in D.07-09-045. Storage revenues allocated to load balancing are included in unbundled transmission rates.

(Continued)

Advice Letter No:	3060-G-A	*Issued by*	*Date Filed*	December 22, 2009
Decision No.	05-06-029	***Brian K. Cherry***	*Effective*	January 1, 2010
		Vice President	*Resolution No.*	
2C12		*Regulatory Relations*		

Table 1(continued). Excerpt from Advice 3060-G-A Annual Gas True-Up filing for Rates Effective January 1, 2010.

Pacific Gas and Electric Company
San Francisco, California
U 39

	Revised	*Cal. P.U.C. Sheet No.*	27954-G
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	27781-G

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 3

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

	Amount ($000)					
Description	Core	Noncore	Unbundled	Core Procurement	Total	
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (4):						
Illustrative Gas Supply Portfolio				1,852,955 (R)	1,852,955 (R)	
Interstate and Canadian Capacity				216,719 (I)	216,719 (I)	
WGSP – Procurement – Residential				2,476 (R)	2,476 (R)	
F&U (on items above and Procurement Account Balances Below)				25,270 (R)	25,270 (R)	
Backbone Capacity (Incl. F&U)	(61,697) (I)			61,697 (I)	0	
Backbone Volumetric (Incl. F&U)	(18,698) (I)			18,698 (R)	0	
Storage (Incl. F&U)	(42,093)			42,093	0	
Carrying Cost on Noncycled Storage Gas (Incl. F&U)	(1,757)			1,757	0	
Core Brokerage Fee (Incl. F&U)				9,581	9,581	
Procurement Account Balances				11,692 (I)	11,692 (I)	
Illus. Core Procurement Revenue Requirement	(124,245) (I)			2,242,938 (R)	2,118,693 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	1,263,524 (I)	110,730 (I)	168,343 (R)	2,242,938 (R)	3,785,535 (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (5):						
Energy Efficiency (EE)	58,377 (R)	6,498 (R)			64,875 (R)	
Low Income Energy Efficiency (LIEE)	55,734 (I)	6,204 (I)			61,938 (I)	
Research, Demonstration and Development (RD&D)	6,725 (R)	3,861 (I)			10,586 (I)	
CARE Administrative Expense	1,113 (R)	730 (I)			1,843 (I)	
BOE and CPUC Administrative Cost	188 (I)	108 (I)			296 (I)	
PPP Balancing Accounts	1,858 (R)	(4,348) (R)			(2,490) (R)	
CARE Discount Recovered from non-CARE customers	66,085 (I)	43,348 (I)			109,433 (I)	
Total PPP Funding Requirement in Rates	190,080 (I)	56,401 (I)			246,481 (I)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	1,453,604 (I)	167,131 (I)	168,343 (R)	2,242,938 (R)	4,032,016 (R)	
Low Income Energy Efficiency Not In Rates	0 (R)	0 (R)			0 (R)	(D)
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	1,453,604 (I)	167,131 (I)	168,343 (R)	2,242,938 (R)	4,032,016 (R)	

(4) The credits shown in the Core column represent the core portion of the Gas Accord RRQ that is included in the Illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost includes a forecast of carrying cost on cycled gas in storage, and an illustrative commodity and shrinkage cost based on the Weighted Average Cost of Gas (WACOG) of $0.59828 per therm. Actual gas commodity costs change monthly. WGSP costs, approved in AL 3039-G, will be recovered in residential rates effective April 1, 2010. (T) (T)

(5) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2010 PPP surcharge AL 3057-G and includes LIEE program funding adopted in D.08-11-031, EE program funding adopted in D.09-10-027, CARE annual administrative expense adopted in D.08-11-031, and excludes F&U per D.04-08-010. (T) (D)

(Continued)

Advice Letter No:	3060-G-A	*Issued by*	*Date Filed*	December 22, 2009
Decision No.	05-06-029	***Brian K. Cherry***	*Effective*	January 1, 2010
		Vice President	*Resolution No.*	
3C15		*Regulatory Relations*		

Table 2. Excerpted from Advice 3518-E-A Annual Electric True-Up filing for Rates Effective January 1, 2010.

Table 2: Annual Electric True-Up Projected 2010 Revenue Requirements

Line #		Test Year 2010 RRQ A	12/31/09 Forecast Under/(Over) collected BA Amortization B	Total Projected 2010 Revenues C = A + B
1	**CPUC Jurisdictional**			
2	**Distribution**			
3	Distribution/DRAM[1]	3,058,541,472	140,907,862	3,199,449,334
4	Self Generation Incentive Program	30,186,419	0	30,186,419
5	Environmental Enhancement	10,102,550	0	10,102,550
6	CPUC Fee	20,644,796	0	20,644,796
7	Advanced Metering/SBA	107,497,541	32,573,331	140,070,872
8	Demand Response/DREBA/DRRBA	35,914,565	715,457	36,630,022
9	Air Conditioning Cycling/ACEBA/DRRBA	48,613,035	0	48,613,035
10	ClimateSmart	0	0	0
11	California Solar Initiative	106,076,775	0	106,076,775
12	HSM	0	8,986,589	8,986,589
13	ATFA	0	(254,962)	(254,962)
14	CEMA	0	5,922,000	5,922,000
15	PCBA	0	0	0
16	CEEIA	29,382,897	2,031,108	31,414,005
17	NTBA	0	0	0
18	LCPERMA	0	346,248	346,248
19	DPMA	0	0	0
20	**Generation**			
21	Utility Retained Generation Base/UGBA	1,340,530,602	324,313,742	1,664,844,344
22	Electric Procurement/ERRA	3,731,717,921	81,210,898	3,812,928,819
23	DWR--Power Charge/PCCBA	930,339,038	73,825,458	1,004,164,496
24	DWR Franchise Fees	10,822,923	0	10,822,923
25	BCRSBA	0	(976,899)	(976,899)
26	FERABA[2]	0	4,499,049	4,499,049
27	HA	0	0	0
28	LTAMA	0	290,941	290,941
29	MRTUMA	0	0	0
30	RPSCMA	0	0	0
31	CARB	0	0	0
32	**Ongoing CTC/MTCBA**	353,029,017	47,732,678	400,761,695
33	**Rate Reduction Bond Memorandum Account**[1]	0	0	0
34	**Energy Cost Recovery Bonds**			
35	(1) Dedicated Rate Component Series 1	303,859,661	0	303,859,661
36	(2) Dedicated Rate Component Series 2	152,788,191	0	152,788,191
37	(3) ERB Balancing Account (ERBBA)	(23,686,226)	(117,415,768)	(141,101,994)
38	**Nuclear Decommissioning**	25,697,000	336,624	26,033,624
39	**Public Purpose Programs**	0	0	0
40	(1) Energy Efficiency	120,670,462	0	120,670,462
41	(2) RDD	35,217,516	0	35,217,516
42	(3) Renewables	36,826,418	0	36,826,418
43	(4) LIEE	90,043,760	0	90,043,760
44	PPPRAM	0	(5,077,665)	(5,077,665)
45	CAREA	7,448,408	52,070,991	59,519,399
46	Procurement EE/PEERAM	250,724,532	4,076,633	254,801,165
47	**DWR Bonds**	411,132,926	0	411,132,926
48	**Total CPUC Jurisdictional**	**11,224,122,199**	**656,114,315**	**11,880,236,514**
49	***CPUC Revenues at Present Rates***			**11,456,693,992**
50	***Change in CPUC Jurisdictional***			423,542,522
51	***Total FERC Jurisdictional***			719,546,627
52	***FERC Revenues at Present Rates***			**751,113,742**
53	***Change in FERC Jurisdictional***			(31,567,115)
54	**Grand Total Projected Revenues**			**12,599,783,141**
55	**Total Revenues at Present Rates**			**12,207,807,734**
56	**Total Change**			**391,975,407**

Notes:
1 The 12/31/09 forecast Distribution/DRAM balance includes the 12/31/09 forecast Rate Reduction Bond Memorandum Account balance as authorized in AL 3502-E.
2 The 12/31/09 forecast FERABA balance of $4,499,049 includes a discount portion of $3,835,228, which gets allocated to generation rates; and administrative costs of $663,821 which gets allocated to distribution rates.

Requests Impacting Customer Rates
Filed During the Year of 2010
SB 695 Reporting Requirement

Filing Description	Anticipated Filing Date	Expected Implementation	Impacted Rate	Impacted Rate Component
Q1 2010				
March 1 Rate Change (To Implement TO12 Rates)	Jan	3/1/10	Electric	Transmission
Rate Design Window 2010 (Peak Time Rebate)	Jan	5/1/11	Electric	Energy/Generation
Diablo Seismic Survey (3D)	Jan	1/1/12	Electric	Energy/Generation
ERRA 2009 Compliance Filing - Includes MRTU Cost Recovery	Feb	--	Electric	Energy/Generation, Competition Transition Charge (CTC)
Rate Design Window 2010/ Peak Time Rebate	Feb	5/1/11	Electric	Distribution
Rate Relief Summer 2010	Feb	6/1/10	Electric	All rate components
Accelerate Generator Settlement Refunds (1)	Feb	6/1/10	Electric	Energy Revenue Bonds
Accelerate TO11 Refunds (1)	Mar	6/1/10	Electric	Transmission
General Rate Case (GRC) 2011 Ph II - Dynamic Pricing	Mar	5/1/11	Electric	PPP, Distribution, Energy/Generation, Competition Transition Charge (CTC)
General Rate Case (GRC) 2011 Ph II - Gas	Mar	5/1/11	Gas	Energy, Distribution, Public Purpose Programs/Mandated Programs
Q2 2010				
Energy Resource Recovery Account (ERRA) 2011 Forecast	Jun	1/1/11	Electric	Energy/Generation, Competition Transition Charge (CTC)
Core Procurement Incentive Mechanism Sharehold Award	TBD	10/1/10	Gas	Energy (gas procurement)
Q3 2010				
FERC - TO13	Jul	3/1/11	Electric	Transmission
Winter Gas Savings Program (2010-2011)	Aug	9/13/10	Gas	Energy (gas procurement), Distribution
Annual Electric True-Up (AET) 2011	Sep	1/1/11	Electric	Transmission, PPP, Distribution, Energy/Generation, DWR, CTC, ERB
DWR 2011 Revenue Requirement Forecast Filing	TBD	TBD	Electric	DWR
Real Time Pricing - Residential Default	TBD	TBD	Electric	Energy/Generation
Q4 2010				
FERC TRBA/ECRA/RSBA Filing	Oct	1/1/11	Electric	Transmission
Public Purpose Program Surcharge Gas Rate Filing 2010 - Advice Letter	Oct	1/1/11	Gas	Public Purpose Programs/Mandated Programs
SB 695 Res Rate Change (T1 & T2) Advice Letter	Nov	1/1/11	Electric	Distribution, Energy/Generation
Energy Resource Recovery Account (ERRA) 2010 Forecast - Update	Nov	1/1/11	Electric	Energy/Generation, Competition Transition Charge (CTC)
Annual Gas True-Up (AGT) 2011	Nov	1/1/11	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage
Annual Gas True-Up (AGT) 2011 - Advice Letter Update	Dec	1/1/11	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage
Annual Electric True-Up (AET) 2011 - Advice Letter Update	Dec	1/1/11	Electric	Transmission, PPP, Distribution, Energy/Generation, DWR, CTC, ERB
FERC TACBA Filing	Dec	3/1/11	Electric	Transmission

Southern California Edison

1. Opening Comments

In support of Senate Bill (SB) 695, SCE is providing the following information to assist the Commission in preparing its annual report to the Governor and Legislature. Specifically, SB 695 requires:

> "that by May 1, 2010, and by May 1 of each year thereafter, the commission also report to the Governor and Legislature with its recommendations for actions that can be undertaken during the upcoming year to limit cost and rate increases, consistent with the state's energy and environmental goals, including the state's goals for reduction in emissions of greenhouse gases. The bill would require the commission to annually require electrical and gas corporations to study and report to the commission on measures that they recommend be undertaken to limit costs and rate increases."

The information provided includes SCE's overall rate policy, a description of SCE's rate components included on customers' bills, the current revenue requirement included in rates plus anticipated changes during the rest of 2010. SCE has provided information that includes known filings that will be made throughout the next twelve months that will affect future rates. And finally, SCE has included a summary of policies for limiting rate increases while meeting the State's energy and environmental goals for reducing greenhouse gases and recommendations for the Commission and legislature to help minimize rate increases in the future.

2. Overall Rate Policy

SCE's overall rate policy is to fully recover the costs of efficiently serving its customers in an equitable manner while considering public policy objectives. SCE designs its rates to meet the traditional design objectives (e.g., recovery of revenue requirement, cost of service foundation and stable rates) while supporting the various public policy objectives established by the legislature and regulators. By recovering its authorized revenue requirement, SCE can properly maintain and rebuild its distribution system, provide power as needed, and meet customer service needs as they arise. Recovering these costs equitably from customers ensures that those customers who are more costly to serve pay appropriately higher rates. Rates that are equitable and cost-based also send the correct price signals to customers and prevent uneconomic decisions regarding energy usage.

3. Description of Rate Components and Revenue Requirements

SCE recovers its revenue requirements through the following retail rate components: Generation, Cost Responsibility Surcharge (CRS), New System Generation, Distribution, Public Purpose Programs, Nuclear Decommissioning and Federal Energy Regulatory Commission (FERC) jurisdictional Transmission. In addition, SCE is authorized to bill the DWR Power Charge and Bond Charge on behalf of the California Department of Water Resources (DWR).

a. **Generation** – Through the Generation rate component, SCE recovers the costs of its generation portfolio which include the cost of SCE's Utility Owned Generation (UOG) consisting of the fuel, base O&M and capital-related revenue requirements associated with its nuclear, coal, gas, and hydro plants. In addition, SCE recovers all of its purchased power costs required to meet its load not met by its UOG or DWR Power contracts through this rate component. The purchased power costs include the costs of Qualifying Facility (QF) contracts, all other bilateral contracts that SCE has entered into since 2003 when the company was authorized to resume the power procurement function and make purchases and sales through the wholesale markets.

b. **Cost Responsibility Surcharge** – Through the CRS, SCE recovers from customers that have elected to purchase their generation service from other providers (e.g. Direct Access (DA) customers), the above market costs of the combined SCE and DWR generation portfolios. The revenue generated from the CRS is credited back to SCE's bundled service customers so that they remain indifferent to the departure of those customers, and are not burdened with paying for the above-market costs of the procurement SCE had planned and incurred to serve the departed customers.

c. **New System Generation** – Through the New System Generation (NSG) rate component, SCE recovers the costs of those "new generation" assets that the Commission has required SCE to procure in order to maintain system reliability for the benefit of all customers. The NSG revenue requirement includes the contracted procurement costs less the value of the energy produced. The net cost, or capacity cost, is recovered from all customers who benefit from the additional system capacity provided by the new generation, including DA and Community Choice Aggregation (CCA) customers.

d. **Distribution** – Through the Distribution rate component, SCE primarily recovers its base distribution O&M costs and its capital-related revenue requirement. In addition, the Commission has authorized SCE to recover its Edison SmartConnect revenue requirement, Demand Response program funding, California Solar Initiative program funding and some Energy Efficiency incentives through the Distribution rate component. The Commission has authorized SCE to provide the California Alternate Rate for Energy (CARE) discount to the income-qualified customers through the Distribution rate component.

e. **Public Purpose Programs Charge (PPPC)** – Through the PPPC component, SCE recovers the legislatively mandated Public Goods Charge funding for the California Energy Commission administered Research Development and Demonstration and Renewable programs, plus SCE- administered Energy Efficiency programs. In addition, through this rate component SCE recovers additional program funding authorized by the Commission for Procurement Energy Efficiency, and Low-Income programs. The Commission has authorized SCE to recover the costs of the CARE program including the discount provided to CARE-eligible customers from all non-CARE customers through the PPPC.

f. **Nuclear Decommissioning** – Through the Nuclear Decommissioning rate component, SCE recovers the customers' portion of the Nuclear Decommission Trust funding authorized by the Commission to be used to decommission SCE's share of the San Onofre and Palo Verde Nuclear Generating Stations. In addition, SCE recovers costs associated with the storage of spent nuclear fuel through this rate component.

g. **FERC-Jurisdictional Transmission** – SCE's FERC-jurisdictional transmission rate is comprised of five components: 1) Base Transmission which recovers the O&M and capital-related revenue requirement associated with typically higher voltage transmission assets under FERC's jurisdiction; 2) Construction Work in Progress incentives; 3) flow-through to customers of transmission revenues generated through wholesale customers' use of the transmission system; 4) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 5) Transmission Access Charge which reflects the net contribution by SCE's customers to the transmission revenue requirements of all participating transmission owners in the CAISO system.

h. **DWR Power Charge and Bond Charge** – In early 2001, as the result of the energy crisis and Assembly Bill (AB)1X, DWR entered into long term power contracts that were necessary to meet the state's Investor Owned Utilities' (IOUs') net short requirements. The Commission has authorized SCE to recover on behalf of DWR, the revenue requirement associated with these contracts through the DWR Power Charge. In addition, in order to recover the costs DWR incurred in early 2001 to purchase energy on behalf of IOUs' customers from dysfunctional wholesale markets which were initially financed by the State's General Fund, the Commission authorized SCE to bill the DWR Bond Charge. All of the revenues associated with the DWR Power and Bond Charges are collected by SCE and passed on to DWR.

4. Summary of Revenue Requirements by Rate Component

a. Revenue Requirements and System Average Rate for Bundled Service customers as of March 1, 2010:

	Rate Component	($millions)	%	SAR c/kWh
1.	Generation	4,691	42.6%	6.3
2.	New System Generation	109	1.0%	0.1
3.	Distribution	3,719	33.8%	4.7
4.	Public Purpose Programs	578	5.3%	0.7
5.	Nuclear Decommissioning	53	0.5%	0.1
6.	FERC Transmission	614	5.6%	0.8
7.	DWR Power and Bond	1,242	11.3%	1.6
8.	TOTAL System	11,006	100.0%	14.3

b. Revenue Requirement/Rate Changes in the coming 12 months

As shown in Appendix A, the only revenue requirement and rate change planned at this time to be implemented during the rest of 2010, is a reduction in the FERC jurisdictional Transmission Access Charge Balancing Account Adjustment scheduled for June 1, 2010. This rate change will be implemented concurrently with the change from winter to summer rates.

c. Management Control of Revenue Requirements

SCE requests in CPUC and FERC General Rate Cases funding to operate its generation, transmission and distribution businesses in order to provide reliable electric service to all customers in its service territory. Based on the funding authorized by the Commission, SCE has the ability to manage those core utility businesses. Another portion of SCE's total revenue requirement is associated with its power procurement function. Based on a set of assumptions that adhere to regulatory and legislative policies, SCE requests funding to procure enough power to meet its customers' load. Although there are procurement cost components that are outside of SCE's control, such as natural gas prices, SCE can use hedging tools to minimize the variability in cost of power to its customers. A third category of costs are associated with policies driven by Commission and the Legislature for funding programs such as Demand Response, Energy Efficiency, Solar Initiatives, Self Generation and Low Income programs. In compliance with these policies, SCE makes initial requests for funding these programs but the final authorized funding amounts are determined by the Commission based on its policy objectives. Finally, there are costs included in the total revenue requirement that are fully outside of SCE's management control such as DWR Power and Bond Charge revenue requirements and other costs whose magnitude are prescribed by the legislature (e.g., Assembly Bill 1890 required payments of certain amounts by SCE to the California Energy Commission for funding its Renewable, and Research, Development and Demonstration programs).

5. Sales Forecasts

The Commission adopted SCE's 2010 total sales forecast of 83,435 GWhs in Decision (D.)10-02-019 (SCE's 2010 ERRA Forecast Proceeding). This represents a decrease from recorded 2009 sales of approximately 3%. SCE estimates sales to fall in 2010 as the result of: 1) assuming normal weather patterns, 2) continuing negative impacts of the economic recession, 3) slower customer growth, and 4) increased levels of energy efficiency. The effect of the economy's decline is reflected in both the 2010 forecast of per capita personal income and in the number of customer additions. Employment growth is not expected to turn positive in SCE's service area until mid-2010. Although decreases in the sales/load forecast results in lower procurement costs; overall, a decrease in sales puts upward pressure on rate levels because all of the "fixed" costs of the system must be recovered over fewer kWh sales.

6. 2010 Outlook

See Appendix A for a list and timing of known cases affecting rates during 2010.

7. Utility's Policies For Limiting Rate Increase While Meeting State's Energy and Environment Goals for Reducing Greenhouse Gases

To achieve these goals, SCE promotes all cost-effective energy efficiency and demand response measures. SCE also delivers more renewable energy to its customers than any other utility in the nation and seeks to achieve the State's goals at the lowest cost. In addition, SCE is exploring the use of new technologies such as energy storage to more cost-effectively integrate the intermittent renewable energy sources into its system. Lastly, SCE is undertaking strategies to improve the load factor on its system by supporting off-peak use of energy by plug-in electric vehicles and by empowering customers to manage their bills by shifting their usage to off-peak hours through the installation of Edison SmartConnect meters and promotion of efficient and dynamic pricing structures. Improving the system load factor will result in more efficient utilization of the existing generation capacity and lower rates.

8. Recommendations for CPUC and Legislature to Help Minimize Rate Increases in the future

California leads the nation in promoting reduction in GHG emissions, use of renewable energy, adoption of advanced technologies and social programs to help the needy families. The costs associated with implementing these policies place upward pressure on utilities' rates. In addition, due to mild weather and implementation of energy efficiency measures, the electricity usage per residential customer in California is well below the national average. These factors also lead to higher rates.

SCE supports these policies, but believes that the utilities should be provided more flexibility in implementing them to achieve lower costs for customers. For example, policies which create significant artificial limitations on accessing the markets for renewable energy will result in less renewable development, slower implementation, and higher costs to customers. Alternatively, broad access to markets with high levels of competition will provide greater opportunities for renewable projects, earlier achievement of the State's goals, and lower prices for customers. Flexible policies will benefit customers; rigid policies hamper achievement of the State's goals and increase customer costs.

In addition, SCE's rate levels could increase if the Commission requires SCE to procure resources to maintain system reliability on behalf of all benefiting customers but does not implement an appropriate cost allocation mechanism to allocate the cost of such resources to all such customers, or disproportionately imposes costs on SCE's bundled service customers.

Lastly, customers are generally focused on their bills rather than rate levels. The legislature and the CPUC should promote measures that empower customers to manage their energy usage and minimize the distortion in rates that result in significant hidden subsidies in rate structures from some customers to others. SCE believes that the cost of subsidies to needy customers or subsidies to customers taking advantage of programs such as Net Energy Metering (NEM) should be transparent as a separate rate component and the rate structures should not deviate from their cost basis to provide additional hidden subsidies to a particular group of customers.

Southern California Edison
Appendix A: list and timing of known cases affecting rates during 2010.

Key Regulatory Filings with Rate Impacts - Southern California Edison Co.	Estimated Filing Timing	Rates Effective
Q1 2010		
Jan 1 Rate Change (To Implement DWR and FERC Balancing Accounts)	Dec '09	1/1/10
2009 Rate Design Window Filing (capping DR credits)	Dec '09	6/1/10
March 1 Rate Change (Consolidated Rate Change, including 2010 FERC GRC)	Feb	3/1/10
Q2 2010		
ERRA 2009 Compliance Filing - Includes MRTU Cost Recovery and review of Mohave-related costs	Apr	--
FERC Transmission Access Charge Balancing Account Rate Change	Feb	6/1/10
Q3 2010		
Energy Resource Recovery Account (ERRA) 2011 Forecast	Aug	1/1/11
FERC - 2011 GRC	Aug	10/1/2010 or 03/1/2011
DWR 2011 Revenue Requirement Forecast Filing	TBD	TBD
Dynamic Pricing Filing (per D.09-08-028)	Sep	1/1/12
Q4 2010		
FERC TRBA/RSBA Filing	Oct	1/1/11
SB 695 Res Rate Change (T1 & T2) Advice Letter	Nov	1/1/11
Energy Resource Recovery Account (ERRA) 2011 Forecast - Update	Nov	1/1/11
Jan 1 Rate Change (To Implement DWR and FERC Balancing Accounts)	Dec	1/1/11
2012 GRC Phase 1 Application	Dec	1/1/12

B. *Southern California Gas Company*

SB 695 Report To California Public Utilities Commission

Southern California Gas Company (SCG) appreciates the opportunity to provide input to the California Public Utilities Commission (CPUC or Commission) in response to SB 695-enacted changes to PUC Section 748. SCG's objective in developing this inaugural report is to provide useful information that the CPUC may consider as it prepares its annual report for the Governor and Legislature. This report provides data related to gas revenue requirements and rates. This report is structured as per the Energy Division's request: overall rate policy at SCG, description of revenue requirement components, discussion of rate components, management of rate components, and 2010 CPUC filing outlook (as appendix). SCG's recommendations for actions that can be undertaken to reduce cost and rate increases are provided at the conclusion of this report.

I. Introduction

The information provided in this report includes SCG's overall rate policy, a description of the rate components, current revenue requirements and anticipated changes during 2010. And finally, SCG has included a summary of policies for limiting customer rate impacts while meeting the State's energy and environmental goals for reducing greenhouse gases.

Within the frameworks outlined by the CPUC and the Legislature, SCG seeks to fairly allocate costs across its customer classes. However, SCG recognizes that allocations of certain components of gas service costs in rates are beyond its direct control. SCG hopes that the CPUC will consider the recommendations put forth in later sections of this report, which SCG believes can have a measureable near-term impact on its total cost of delivering safe, reliable, cost-effective gas services to its customers in California.

II. Overall Rate Policy

SCG strives to provide its customers with reasonable rates for safe and reliable gas service while understanding that its customers value transparency and stability. Therefore, SCG also seeks to minimize the impact of rate adjustments made throughout the year. SCG like the other gas utilities in California makes monthly advice letter filings to change the gas commodity rate based on the monthly cost of gas and seeks an annual gas transportation and Public Purpose Program (PPP) surcharge rate change in January of each year. In addition, SCG submits various filings to the Commission throughout the year in response to specific Commission directives or changes to the utility business, to ensure that SCG provides reliable and cost effective service to its customers.

III. Description of Revenue Requirement Components

This section outlines major categories of gas revenue requirements (RRQ) as commonly monitored within SCG:

Gas revenue requirements are commonly grouped into the following four major categories: Energy Costs or Weighted Average Cost of Gas (WACOG), Transportation, Gas Storage, and Public Purpose Programs.

	2009			2010		
Revenue Component	Revenue Requirement $(000)		Percentage	Revenue Requirement $(000)		Percentage
Energy[1]	1,393,951	1	42.75%	2,042,363	2	50.43%
Transportation	1,594,112		48.89%	1,731,329		42.75%
Gas Storage	24,575	3	0.75%	25,615	3	0.63%
PPP	272,410		8.35%	276,241		6.82%
Total	3,260,473		100.00%	4,049,933		100.00%

[1]Actual recorded revenue that reflects the sum of the procurement rate multiplied by the corresponding consumption for each month from January 2009-December 2009.
[2]Represents estimates of Res and Core C&I usage based on average monthly consumption for years 2008 and 2009 multiplied by average monthly approved GPC rate for years 2008 and 2009.
[3]A subset of Transportation

1) WACOG revenue requirements represent approximately 50.43%of the total gas revenue requirement in the upcoming 12months. The revenue requirements are expected to continue to trend upward, consistent with the market price of natural gas. For 2009, the energy revenue requirement represented about 42.75% of the total authorized gas revenue requirements.

2) Transportation revenue requirements, constitute about 42.75%of the total gas revenue requirements in the upcoming 12 months. For 2009, the transportation revenue requirement constituted about 48.89% of the total authorized gas revenue requirements. The increase in the revenue requirement is primarily due to attrition and amortization of balancing accounts.

3) Gas storage revenue requirements comprise approximately 1% of the total revenue requirement in 2009, and that level is forecast to remain fairly constant in 2010.

4) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent approximately 6.82%of the total gas revenue requirements. The revenue requirements are expected to trend upward mainly due to increases in expected gas program penetration levels (Energy Efficiency goals) and the

CARE shortfall, which is driven by the cost of gas and CARE participation. For 2009, these programs contributed about 8.35% of the total authorized gas revenue requirements.

IV. Description of Rate Components

Revenue requirements (RRQ) discussed in the previous section directly aligns with rate components. At the highest level, gas rates can be described as revenue requirements divided by sales, so both revenue requirement changes and demand variations impact the actual rates for gas service. So, those RRQ expected to increase in the coming twelve months, will tend to drive rates up. For those RRQ which trend down, rates similarly will be reduced. And, the rate pressures created by RRQ are modulated by differences in actual sales versus prior estimates (used to set rates). Adjustments in the allocation of revenue requirement across customer classes and tiers also impact the rates experienced by individual customers.

Customer sales volatility across time directly impact the rates experienced by gas customers. If revenues collected from customers are impacted (higher or lower) due to volatility in sales, future rates will be adjusted (decreased or increased) in order to ensure revenues collected are at authorized levels. SCG reviews load forecasts for its service territory on a regular basis.

V. Management of Key Rate Components

SCG is committed to controlling costs while providing safe and reliable gas service to its customers. However, there are many key drivers that affect customers' rates which fall outside of SCG's control. Among these include: the market price of the gas commodity actual sales volumes, weather, natural disasters, interest rates, and permitting process delays. Despite these factors, SCG diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

VI. 2010 CPUC Filing Outlook

Attached for your reference is Appendix A, which reflects key filings' data provided previously to the Energy Division (December 2009). This is not an exhaustive list of SCG's filings that may occur in 2010; rather it incorporates regulatory filings which are known at this time to have a rate impact for gas customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized are subject to change via the normal regulatory approval processes of the Commission and FERC.

VII. Recommendations to the CPUC and Legislature

In this section, SCG offers a set of recommendations for actions that the Commission may consider as it prepares its own annual report to the Legislature and Governor on measures that can be undertaken in the coming year to limit utility costs and rate increases. These recommendations center on factors largely out of the scope of the utilities' control, and are expected to have a significant impact on utility costs and resultant customer rates in the near- to medium-term.

SCG continues to use best operating and infrastructure investment practices to limit rate increases while still meeting California's energy efficiency and environmental goals, in order to reduce greenhouse gases (GHG). To achieve these goals, SCG adheres to the State's Energy Action Plan by promoting all mandated energy efficiency programs in pursuit of State and CPUC approved goals. In addition, SCG is exploring the use of new technology helping to shape an overall more cost effective energy model including empowering customers to manage their bills by evaluating their usage through the installation of Smart Meters.

In the coming year, SCG recommends that several key State policies and procedures should be shaped to support more effective, efficient and beneficial use of revenues collected from SCG's customers. SCG believes that the State will have to weigh its environmental goals and desire for reliability that cause significant upwards cost pressures against its desire to moderate impacts on customers' rates for gas service. Here is a list of items in which policy decisions could drive customer rate impacts.

1. Smart Meter Policy

2. GHG Compliance Policies

3. Combined Heat and Power (CHP)

4. Performance-Based Incentives Mechanisms

In summary, California leads the nation in promoting reduction in GHG emissions, adoption of advanced technologies and social programs. The associated with implementing these policies place upward pressure on utilities' rates. In addition, due to the mild weather and implementation of energy efficiency measures, the gas usage per customer in California is below the national average. These factors also lead to higher rates. SCG supports these policies, however, believes that the utilities should be provided more flexibility in implementing then to achieve lower costs for customers.

Appendices

Appendix A - Key Filings Table

Southern California Gas Company
Requests Impacting Customer Rates
During 2010

Description	Filed	Expected Implementation	Rate Impacted	Directional Impact
Gas Regulatory Account Update AL	October 2010	January 2011	Gas Transportation	Increase
Gas Consolidated AL	December 2010	January 2011	Gas Transportation	Increase
Gas Public Purpose Program Update AL	October 2010	January 2011	PPP Surcharge	Increase

C. *San Diego Gas and Electric Company*

SB 695 Report To California Public Utilities Commission

San Diego Gas & Electric (SDG&E) appreciates the opportunity to provide input to the California Public Utilities Commission (CPUC or Commission) in response to SB 695-enacted changes to PUC Section 748. SDG&E's objective in developing this inaugural report is to provide useful information that the CPUC may consider as it prepares its annual report for the Governor and Legislature. This report provides data related to both gas and electric revenue requirements and rates. This report is structured as per the Energy Division's request: overall rate policy at SDG&E, description of revenue requirement components, discussion of rate components, management of rate components, and 2010 CPUC filing outlook (as appendix). SDG&E's recommendations for actions that can be undertaken to reduce cost and rate increases are provided at the conclusion of this report.

II. Introduction

The information provided in this report includes SDG&E's overall rate policy, a description of the rate components, current revenue requirements and anticipated changes during 2010. And finally, SDG&E has included a summary of policies for limiting customer rate impacts while meeting the State's energy and environmental goals for reducing greenhouse gases.

Within the frameworks outlined by the CPUC and the Legislature, SDG&E seeks to fairly allocate costs across its customer classes. However, SDG&E recognizes that allocation of certain components of electric and gas service costs in rates are beyond its direct control. SDG&E hopes that the CPUC will consider the recommendations put forth in later sections of this report, which SDG&E believes can have a measureable near-term impact on its total cost of delivering safe, reliable, cost-effective gas and electric services to its customers in California.

II. Overall Rate Policy

SDG&E strives to provide its customers with reasonable rates for safe and reliable gas and electric service while understanding that its customers value transparency and stability. Therefore, SDG&E also seeks to minimize the impact of rate adjustments made throughout the year. Generally, SDG&E requests CPUC jurisdictional electricity rate changes two times per calendar year (January and May). For gas rate changes, SDG&E like the other gas utilities in California, makes monthly advice letter filings to change the gas commodity rate based on the monthly cost of gas and seeks an annual gas transportation and Public Purpose Program (PPP) surcharge rate change in January of each year. In addition, SDG&E submits various filings to the Commission throughout the year in response to specific Commission directives or changes to the utility business, to ensure that SDG&E provides reliable and cost effective service to its customers.

SDG&E also undertakes efforts to manage the timing of revenue changes and subsequent rate changes. For example, in 2009, SDG&E minimized swings in customer's rates and bills via implementation of a one-time Energy Resource Recovery Account bill credit to electricity customers from balancing account overcollections[1]. Also, to decrease pressure on customer bills during 2009, SDG&E, along with Southern California Edison (SCE), requested and received authorization to defer collection of the approved revenue requirements for the California Solar Initiative (CSI) benefiting electricity customers during these tough economic times without jeopardizing the payment of CSI incentives or the future success of the program[2].

III. Description of Revenue Requirement Components (Gas and Electric)

This section outlines major categories of gas and electricity revenue requirements (RRQ) as commonly monitored within SDG&E:

Electricity cost categories include Commodity/Generation (including DWR), Competition Transition Charge (CTC), Nuclear Decommissioning, Transmission, Distribution, and Public Purpose Programs (PPP). For example, Commodity/Generation would include purchased power costs, utility-owned generation costs, Department of Water Resources charges (DWR), and other revenue requirements linked to generating and procuring the electricity commodity. Relative ranges for each RRQ category as a percent of total authorized 2009 RRQ, and analogous forecast trends for 2010, are provided and discussed below. Note that the focus is not on specific filings brought forth to the Commission, but rather categories of revenue requirements that could have a potential impact on future rates.

[1] Authorized in CPUC D.09.09.042 on September 24, 2009.
[2] Authorized in CPUC D.08.12.004 on December 4, 2008.

	2009		2010	
Revenue Component	**Revenue Requirement $(000)**	**Percent**	**Revenue Requirement $(000)**	**Percent**
Commodity[1]	1,688,530	54.64%	1,444,057	47.67%
CTC	44,414	1.44%	46,908	1.55%
ND	10,298	0.33%	9,606	0.32%
Transmission	236,759	7.66%	274,708	9.07%
Distribution	1,034,362	33.47%	1,115,776	36.83%
PPP	75,640	2.45%	138,395	4.57%
Total	3,090,003	100.00%	3,029,450	100.00%

[1] Includes expected 2010 ERRA Forecast rate change on May 1, 2010.

1) The largest piece of SDG&E's revenue requirement is Commodity/Generation which is currently 47.67% of total revenue requirement and is generally expected to increase over time primarily due to increasing electricity procurement costs related to renewable energy costs and increasing natural gas prices. Most recently, favorable gas prices and delays in contracted renewable resources coming on-line have caused commodity prices to trend downward. In total, DWR charges comprise approximately 22% of SDG&E's forecast 2010 revenue requirement, and are expected to decline on January 1, 2011 due to the expiration of DWR contracts and timing of indifference (transfer) payments between California's investor-owned utilities. During 2009, DWR-associated revenue requirements were approximately 34% of the total authorized revenue requirement.

2) CTC (Competition Transition Charge) contributes 1.55% of the total revenue requirement in 2010. CTC revenue requirements were 1.44% during 2009.

3) Nuclear Decommissioning revenue requirements represented less than 1% of SDG&E's total authorized revenue requirement during 2009, and that level is forecast to remain fairly constant in 2010.

4) Transmission related revenue requirements constitute 9.07% of the total authorized revenue requirement trending slightly upward.

5) Distribution revenue requirements, including CSI and Smart Meter, comprise approximately 36.83% of the total revenue requirement, up from 33.47% in 2009 primarily due to re-establishing the collection of the CSI revenue requirement in 2010, as discussed previously, and attrition.

6) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represent 4.57% of SDG&E's total revenue requirement during 2010. In comparison, PPP revenue requirements represented 2.45% of the total authorized revenue requirement during 2009.

Gas revenue requirements are commonly grouped into the following four major categories: Energy Costs or Weighted Average Cost of Gas (WACOG), Transportation, Gas Storage, and Public Purpose Programs.

	2009			2010		
Revenue Component	**Revenue Requirement $(000)**		**Percentage**	**Revenue Requirement $(000)**		**Percentage**
Energy[1]	183,234	1	36.43%	248,797	2	42.48%
Transportation	282,327		56.12%	299,256		51.10%
Gas Storage	5,205	3	1.03%	5,205	3	0.89%
PPP	37,482		7.45%	37,568		6.42%
Total	503,043		100.00%	585,621		100.00%

[1]Actual recorded revenue that reflects the sum of the procurement rate multiplied by the corresponding consumption for each month from January 2009-December 2009.
[2]Represents actual recorded revenue up to February 2010. March-Dec 2010 reflects forecasted commodity revenues based on 5 year plan.
[3]A subset of Transportation

5) WACOG revenue requirements represent approximately 42.48% of the total gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to continue to trend upward, consistent with the market price of natural gas. For 2009, the energy revenue requirement represented about 36.43% of the total authorized gas revenue requirements.

6) Transportation revenue requirements, including SmartMeter, constitute about 51.10% of the total gas revenue requirements in the upcoming 12 months. For 2009, the transportation revenue requirement constituted about 56.12% of the total authorized gas revenue requirements. The increase in the revenue requirement is primarily due to attrition and amortization of balancing accounts.

7) Gas storage revenue requirements comprise approximately 1% of the total revenue requirement in 2009, and that level is forecast to remain fairly constant in 2010.

8) PPP revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Energy Efficiency, represents approximately 6.42% of the total gas revenue requirements. The revenue requirements are expected to trend upward in the near future mainly due to increases in the expected gas program penetration levels (Energy Efficiency goals) and the CARE shortfall, which is driven by the cost of gas and CARE participation. For 2009, these programs contributed about 7.45% of the total authorized gas revenue requirements.

IV. Description of Rate Components (Gas and Electric)

Revenue requirements (RRQ) discussed in the previous section directly aligns with rate components. At the highest level, gas and electricity rates can be described as revenue requirements divided by sales, so both revenue requirement changes and demand variations impact the actual rates for gas and electric service. So, those RRQ expected to increase in the coming twelve months, will tend to drive rates up. For those RRQ which trend down, rates similarly will be reduced. And, the rate pressures created by RRQ are modulated by differences in actual sales versus prior estimates (used to set rates). Adjustments in the allocation of revenue requirement across customer classes and tiers also impact the rates experienced by individual customers.

Customer sales volatility across time directly impact the rates experienced by gas and electricity customers. If revenues collected from customers are impacted (higher or lower) due to volatility in sales, future rates will be adjusted (decreased or increased) in order to ensure revenues collected are at authorized levels. SDG&E reviews load forecasts for its service territory on a regular basis. The following section discusses the general trends for gas and electricity loads during 2010.

VIII. Management of Key Rate Components

SD&E is committed to controlling costs while providing safe and reliable gas and electricity service to its customers. However, there are many key drivers that affect customers' rates which fall outside of SDG&E's control. Among these include: the market price of the gas commodity (which also affects the price of the electricity commodity), actual sales volumes, weather, natural disasters, interest rates, and permitting process delays. Despite these factors, SDG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

IX. 2010 CPUC Filing Outlook

Attached for your reference is Appendix A, which reflects key filings' data provided previously to the Energy Division (December 2009). This is not an exhaustive list of SDG&E's filings that may occur in 2010; rather it incorporates regulatory filings which are known at this time to have a rate impact for gas or electricity customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized are subject to change via the normal regulatory approval processes of the Commission and FERC.

X. Recommendations to the CPUC and Legislature

In this section, SDG&E offers a set of recommendations for actions that the Commission may consider as it prepares its own annual report to the Legislature and Governor on measures that can be undertaken in the coming year to limit utility costs and rate increases. These recommendations center on factors largely out of the scope of the utilities' control, and are expected to have a significant impact on utility costs and resultant customer rates in the near- to medium-term.

SDG&E continues to use best operating and infrastructure investment practices to limit rate increases while still meeting California's energy efficiency and environmental goals, in order to reduce greenhouse gases (GHG). To achieve these goals, SDG&E adheres to the State's Energy Action Plan by promoting all mandated demand response and energy efficiency programs in pursuit of State and CPUC approved goals. SDG&E balances the procurement of renewable energy while following the least-cost, best-fit approach to minimize the cost to customers. In addition, SDG&E is exploring the use of new technology helping to shape an overall more cost effective energy model including empowering customers to manage their bills by shifting their usage to off-peak hours through the installation of Smart Meters and the implementation of dynamic pricing structures.

In the coming year, SDG&E recommends that several key State policies and procedures should be shaped to support more effective, efficient and beneficial use of revenues collected from SDG&E's customers. SDG&E believes that the State will have to weigh its environmental goals and desire for reliability that cause significant upwards cost pressures against its desire to moderate impacts on customers' rates for gas and electricity service. Here is a list of items in which policy decisions could drive customer rate impacts.

1. Smart Grid Policy /Smart Meter Policy

2. Distributed Generation

3. GHG/RPS Compliance Policies

4. Once-Through Cooling Policy

5. Combined Heat and Power (CHP)

6. Performance-Based Incentives Mechanisms

In summary, California leads the nation in promoting reduction in GHG emissions, use of renewable energy, adoption of advanced technologies and social programs. The associated with implementing these policies place upward pressure on utilities' rates. In addition, due to the mild weather and implementation of energy efficiency measures, the electric and gas usage per customer in California is below the national average. These factors also lead to higher rates. SDG&E supports these policies, however, believes that the utilities should be provided more flexibility in implementing then to achieve lower costs for customers.

Appendices

Appendix A - Key Filings Table

San Diego Gas & Electric Company
Requests Impacting Customer Rates During the Year of 2010

Description	Filed	Expected Implementation	Rate Impacted	System Average Directional Impact
2010 ERRA Forecast Application	October 2009	May 2010	Electric Commodity	Decrease
2011 DWR Implementation AL	Nov/Dec 2010	January 2011	Electric Commodity	Decrease
Non-fuel Generation BA Update AL	November 2010	January 2011	Electric Commodity	Increase
FERC TO3 True-up Filing	August 2010	September 2010	Electric Transmission	Increase
CEMA Application - 2007 Wildfires	March 2009	TBD	Electric Distribution	Increase
Z-Factor Application - Ins. Premiums	August 2009	TBD	Electric Distribution	Increase
Electric Regulatory Account Update AL	October 2010	January 2011	Electric Distribution	Increase
Electric Consolidated AL	December 2010	January 2011	All Electric	Decrease
Nuclear Decommissioning Triennal Appl.	April 2009	May 2010	Nuclear Decommissioning	No change
Gas Regulatory Account Update AL	October 2010	January 2011	Gas Transportation	Increase
Gas Consolidated AL	December 2010	January 2011	Gas Transportation	Increase
Electric Public Purpose Program Update AL	October 2010	January 2011	Public Purpose Program	Increase
Gas Public Purpose Program Update AL	October 2010	January 2011	PPP Surcharge	Increase
SB695 Residential Rate Change	November 2010	January 2011	Electric Residential	No change

SUPPORTING DOCUMENTS FOR
DIRECT TESTIMONY OF MICHAEL BROWN

Exhibit 13

Expert Report on Issues Affecting Small Businesses

Testimony of Michael Brown

on behalf of
Small Business Utility Advocates
548 Market Street, Suite 11200
San Francisco, CA 94104
Tel: 415-602-6223 Fax: 415-789-4556

California Public Utilities Commission
Application 12-11-009
May 16, 2013

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

Sheet 1

APPLICABILITY: This schedule* applies to transportation of natural gas for Core End-Use Customers (as defined in Rule 1*) ("Customer") who aggregate their gas volumes and who obtain natural gas supply service from parties other than PG&E. The provisions of Schedule G-CT apply to Core End-Use Customers and to the Core Transport Agents (CTA) who supply them with natural gas and provides or obtains services necessary to deliver such gas to PG&E's Distribution System. Rule 23 also sets forth terms and conditions applicable to Core Gas Aggregation Service. (T) (T)

A group of Core End-Use Customers who aggregate their gas volumes shall comprise a Core Transport Group (Group). The minimum aggregate gas volume for a Group is 12,000 decatherms per year. The Customer must designate a CTA, who is responsible for providing gas aggregation services to Customers in the Group as described herein and in Rule 23. Aggregation of multiple loads at a single facility or aggregation of loads at multiple facilities shall not change the otherwise-applicable rate schedule for a specific facility. Customers electing service under this schedule must request such service for one hundred (100) percent of the core load served by the meter. Schedule G-CT must be taken in conjunction with a core rate schedule. (T)

Core volumes are eligible for service under this schedule, whether or not noncore volumes are also delivered to the same premises. However, core volumes cannot be aggregated with noncore volumes in order to meet the minimum therm requirement for noncore service. Service to core volumes associated with noncore volumes under this schedule applies to all core volumes on the noncore premises.

CTAs, on behalf of a Group, may receive service on PG&E's Backbone Transmission System by utilizing Schedules G-AFT, G-SFT, G-AA, G-NFT, or G-NAA. CTAs may also receive service from PG&E's Storage facilities by utilizing Schedules G-CFS, G-SFS, G-NFS, G-PARK, or G-LEND (N) I (N)

TERRITORY: This schedule applies everywhere within PG&E's natural gas Service Territory.

RATES: Customers taking service under Schedule G-CT will receive and pay for service under their otherwise-applicable core rate schedule; except that Customers who procure their own gas supply will not pay the Procurement Charge specified on their otherwise-applicable core rate schedule.

Pursuant to Schedule G-SUR, Customers will be subject to a franchise fee surcharge for gas volumes purchased from parties other than PG&E and transported by PG&E. Customers will also be responsible for any applicable costs, taxes and/or fees incurred by PG&E in receiving gas to be delivered to such Customers.

See Preliminary Statement, Part B for the Default Tariff Rate Components.

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* PG&E's gas tariffs are available on-line at www.pge.com.

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

SHRINKAGE: Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21.

CURTAILMENT OF SERVICE: Service on this schedule may be curtailed. See Rule 14 for details.

SERVICE AGREEMENT: Before PG&E will provide gas aggregation service under this schedule to a CTA, the CTA and PG&E shall execute a Core Gas Aggregation Service Agreement (Form 79-845) (CTA Agreement) and a Gas Transmission Service Agreement (GTSA) (Form 79-866). (T) (T)

CUSTOMER SIGN-UP PROCESS: The CTA may use one of the two methods specified below for transmitting requests (Customer Authorizations) to PG&E in order to sign up new Customers for Core Gas Aggregation Service, or for switching a Customer from one CTA to another CTA.

Electronic Sign-Up: The CTA shall transmit notice of Customer Authorizations to PG&E using the electronic format acceptable to PG&E, a Direct Access Service Request (DASR). The CTA will pay the switching charges specified in Schedule G-ESP when a DASR is accepted by PG&E. (T)

The CTA may obtain a Customer's Authorization in the same manner set forth for requesting changes in an aggregator or supplier of electric service as specified in Public Utilities Code Section 366.5, including third-party verification where required, and aggregator or supplier liability for the violation of verification procedures (Third-Party Verification Option). Under this option, PG&E shall have no responsibility for verifying the Customer's or CTA's manner of complying with the provisions of Public Utilities Code Section 366.5.

If the Customer Authorization is subject to third-party verification, the CTA shall not electronically submit notice of the Customer's Authorization to PG&E until three (3) business days after the third-party verification, as specified in Public Utilities Code Section 366.5, subdivisions (a) for commercial Customers, or (b) residential Customers, has been performed. In addition to any other right to revoke an offer, a Customer has until midnight of the third (3rd) business day after the day on which the third party verification occurred to cancel a Customer Authorization. A Customer must provide written notice to the CTA at the address specified in their CTA Agreement. If such notice is given by mail, cancellation is effective when the notice is deposited in the mail and it has been properly addressed with postage prepaid. Cancellation by the Customer is effective if it indicates the intention of the Customer not to be bound by the contract. It is the responsibility of the CTA to ensure that all cancellation requests made by Customers are honored, in accordance with Public Utilities Code Section 395. This provides gas Customers with the same cancellation rights that are specified in Public Utilities Code Sections 395 and 396 for electric Customers.

If a Customer cancels its Customer Authorization pursuant to Public Utilities Code Section 395, a Customer Authorization shall not be submitted for that Customer. If a Customer Authorization has already been submitted, the CTA shall, within twenty-four (24) hours, direct PG&E to cancel the Customer Authorization.

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

Sheet 3

CUSTOMER SIGN-UP PROCESS (Cont'd.):

The CTA can also obtain a Customer Authorization by having the Customer sign a copy of the Customer Authorization for Core Gas Aggregation Service (Form No. 79-845, Attachment A), or by signing a form provided by the CTA (CTA Form). The CTA Form must include all of the terms and conditions specified in Attachment A. If the CTA has the Customer sign a CTA Form or a copy of the Attachment A, the CTA shall retain the Customer Authorization for three (3) years and shall provide the original Customer Authorization within three (3) business days of PG&E's request. PG&E reserves the right to review the language in the CTA Form, to ensure it conforms with the language in Attachment A.

After a Customer signs a copy of a CTA Form or the Attachment A, the CTA may electronically submit notice of the Customer's Authorization to PG&E immediately upon the Customer's signing. Third-party verifications are not necessary if the Customer's signature is obtained.

Paper copies of a signed CTA Form or an Attachment A will not be accepted by PG&E for processing.

In accordance with the provisions of gas Rule 3, PG&E may reject any notice of Customer Authorization if the information provided is false, incomplete, or inaccurate in any material respect.

PG&E will accept Customer Authorizations for processing on a first-come, first-served basis. Each Customer Authorization shall be time stamped by PG&E. In the event that more than one Customer Authorization is submitted for a service account, the first valid Customer Authorization for that account will be processed and subsequent requests will be denied until the switch to the pending CTA occurs.

For those Customer Authorizations received and accepted by PG&E on or before the fifteenth (15th) day of any calendar month, Core Gas Aggregation Service will begin no later than the next calendar month's meter reading date for the service account(s) specified on the Customer Authorization. For Customer Authorizations received after PG&E's most recent offer of firm pipeline or storage capacity, PG&E shall not be under (T)
any obligation to offer corresponding capacity to a new CTA or additional capacity to an existing CTA for the remaining month(s) of the current capacity assignment period to serve the accounts specified on such Authorizations. However, PG&E will attempt to include pipeline or storage capacities to service such accounts in PG&E's subsequent pipeline or storage capacity offers to CTAs, provided that it causes no delay in the offer of such capacity by the scheduled offer date as specified below under *Assignment of Firm Pipeline Capacity* and *Assignment of Core Firm Storage.* (T)

By agreement of all participants, PG&E, the CTA, and the Customer may implement a different beginning date for the service requested in a Customer Authorization. No later than five (5) business days before the beginning date of service for a Customer under a Customer Authorization, PG&E shall send Customer usage data to the new CTA. Such data shall be for the past twelve (12) months, or if such data is not available, for the time it is available.

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

Sheet 4

TERM: The initial term (length) of service under a Customer Authorization will be twelve (12) consecutive months from the effective service date. Service shall continue month to month thereafter, regardless of the provisions or terms of any agreement between the Customer and the CTA, and each new Customer Authorization will establish a new twelve (12) month term of service with continuing month to month service thereafter. There is no minimum stay period for a Customer returning to PG&E's procurement service before it can begin a new twelve (12) month term of service under a new Customer Authorization. (T)

TERMINATION OF CUSTOMER AUTHORIZATION: After the expiration of the initial twelve (12) month term, a Customer Authorization may be terminated as specified below:

1. The Customer or the CTA submits to PG&E a notice to terminate the Customer Authorization. Such notice will be referred to as the "Customer Termination". If the CTA submits the Customer Termination electronically, the CTA is obligated to notify the Customer of such termination. For Customers requesting the CTA to terminate service, the CTA shall submit the Customer Termination to PG&E within ten (10) business-days of receiving the Customer's Termination request. For Customer Terminations received and accepted by PG&E on or before the fifteenth (15th) day of a calendar month, PG&E shall terminate Core Gas Aggregation Service to the Customer on the next month's meter reading date. PG&E shall provide procurement service, as specified in the applicable rate schedule, unless the Customer switches to a new CTA as described below. (P)

   All requests and terminations from the CTA must be submitted using the electronic format acceptable to PG&E (DASR), unless otherwise agreed to by PG&E.

2. The Customer directly contacts the CTA or PG&E to request to terminate the Customer Authorization and return to PG&E procurement service, as specified in the applicable rate schedule. Such contact may occur prior to the end of the initial twelve (12) month term but the resulting Customer Termination will not become effective until the initial twelve (12) month term has been completed. If the Customer contacts PG&E on or before the fifteenth (15th) day of any calendar month, Core Gas Aggregation Service will terminate and PG&E will provide procurement service, as specified in the applicable rate schedule, to the Customer no later than the next month's meter reading date for the specified account(s), unless a later month's meter reading date is specified by the Customer. For Customers requesting the CTA to terminate service, the CTA shall submit to PG&E within ten (10) business-days the Customer Termination. (P)

3. A CTA, other than the CTA currently serving the Customer, submits a new Customer Authorization to PG&E requesting that the Customer begin service with the new CTA. If accepted by PG&E, the new Customer Authorization will terminate service from the existing CTA and begin service with the new CTA on the same effective service date. The effective service date will follow switching rules as stated above. Each new Customer Authorization will not become effective until the initial twelve (12) month term of the existing Customer Authorization has expired, or the existing Customer Authorization has been terminated by other means specified herein, and a new twelve (12) month term of service will be established. (T) (T) (T) (T) (T)

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

Sheet 5

TERMINATION OF CUSTOMER AUTHORIZATION (Cont'd.):

At any time, a Customer Authorization may be terminated under the following conditions:

1. The CTA terminates service to the Customer for failure to pay for services provided by the CTA and notifies PG&E, by submitting notice of the termination to PG&E in the electronic format acceptable to PG&E. Upon termination, the Customer will receive PG&E procurement service as specified in the applicable rate schedule. For Customer Terminations received, and accepted by PG&E on or before the fifteenth (15^{th}) day of any calendar month, PG&E procurement service, as specified in the applicable rate schedule, will begin for the specified Customer no later than the next calendar month's meter reading date for the service account specified on the Customer Termination. After June 30, 1999, all requests to terminate service must be submitted in the electronic format acceptable to PG&E, unless otherwise agreed to by PG&E. (D)

2. The Customer no longer receives PG&E service at the meter location specified by the Customer Authorization. In such event, the Customer Authorization for any given account will automatically terminate as of the date the Customer's PG&E gas account is closed. In the event a Customer wishes to obtain Core Gas Aggregation Service or switch to another CTA under a different account, the Customer and CTA must follow Methods 1 or 2 above to implement a new Customer Authorization.

3. A Customer eligible for noncore service chooses to become a noncore Customer. In such event, the Customer Authorization for the specified account will terminate on the date that noncore service begins.

4. The CTA and the Customer mutually agree to terminate service prior to the initial 12-month term by communicating the termination request to PG&E using one of the following methods:

   a) The CTA notifies PG&E by submitting a termination notice to PG&E in the electronic format acceptable to PG&E, or

   (D)

   b) The Customer may directly contact PG&E to request termination. PG&E will accept such a termination request only if the CTA has previously submitted an Authorization For Early Termination (Form 79-845, Attachment H) to PG&E.

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

TERMINATION OF CUSTOMER AUTHORIZATION (Cont'd.):

A CTA Agreement, and all Customer Authorizations for Customers receiving service from the CTA in accordance with that CTA Agreement, shall terminate, regardless of whether the initial twelve (12) month term of a Customer Authorization has expired, if any of the following occur: (T)

1. The CTA goes out of business.

2. PG&E cancels the applicable CTA Agreement due to: (a) the CTA's failure to pay PG&E in accordance with its tariffs for services rendered to the CTA or, (b) for otherwise failing to comply with the terms of Gas Rule 23 or the CTA Agreement or, (c) the CTA's failure to comply with the Firm Winter Capacity Requirement.

3. If a Group's Annual Contract Quantity (ACQ) drops below 12,000 decatherms, the Customer Authorization for each Customer will be terminated, without further notice, effective for each account, as of the next calendar month's meter reading date. When all Customer Authorizations have been terminated the applicable CTA Agreement is canceled automatically. Under paragraphs 2, 3, and 4 above, PG&E will thereafter send written notice of cancellation of the CTA Agreement and all affected Customer Authorizations to the CTA and all affected Customers to the extent practicable, but in no event shall any failure to provide, or a delay in providing, such notice to customers affect PG&E's rights to cancel said CTA Agreement.

If a Customer Authorization is terminated and the Customer continues to receive service at the meter location, the Customer will receive PG&E procurement service as specified in the applicable rate schedule. PG&E may recall capacity, in PG&E's sole discretion, if such capacity is necessary to serve the returning Customer(s); provided, however that PG&E shall not recall such capacity unless and until the aggregated net change due to Customer Terminations exceeds the lower of ten percent (10%) of the CTA's prior effective DCQ or 100 decatherms per day.

The CTA shall remain responsible for any charges due for PG&E service provided under the CTA Agreement prior to its cancellation, whether or not such charges are billed after such cancellation. The Customer shall remain responsible for any charges due for PG&E service provided under the Customer Authorization prior to its termination, whether or not such charges are billed after such termination.

CONTRACT QUANTITIES:

PG&E will process new Authorizations on a monthly basis. For each new Authorization, PG&E shall determine the Annual Contract Quantity (ACQ) for each Customer's account. The ACQ will be based on the Customer's monthly historical gas use.

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

ASSIGNMENT OF FIRM PIPELINE CAPACITY: (N)

Beginning in April 2012, PG&E will periodically offer each CTA an assignment of a pro rata share of the firm pipeline capacity that PG&E holds for its Core Customers on various Canadian pipelines, U.S. interstate pipelines, and PG&E's Backbone Transmission System (each of which is a Pipeline and, collectively, they are the Pipelines). These Pipelines and PG&E's Core capacity holdings are listed below. The first such capacity assignment period will be for April-June 2012, or three (3) months. Each successive capacity assignment period will be for four (4) months. The amount of pipeline capacity that PG&E offers to each CTA will be the Group's January Capacity Factor, described below, multiplied by the firm capacity reserved for PG&E's Core Customers by pipeline and month, as specified below. PG&E will notify the CTA of the firm capacity offer for each pipeline and each month of the applicable capacity assignment period by the fifteenth (15th) day of the month two months prior to the initial month of the capacity assignment period, as specified on the schedule below. The term of the capacity assignment will be one month, with the CTA allowed to accept assignments for any or all of the capacity offered in any or all of the months in the capacity assignment period. The CTA will pay the same rates that PG&E's Core Gas Supply Department pays for the capacity as well as any other applicable rates, fees and charges. For capacity offered to a CTA and not accepted, the CTA will retain some cost responsibility. This is described in more detail below.

For each capacity assignment period, PG&E will determine each Group's January Capacity Factor. Each Group's January Capacity Factor is the ratio of the sum of each Customer's historical January usage to PG&E's forecasted core January throughput, as adopted in PG&E's latest Cost Allocation Proceeding (CAP). PG&E will notify each CTA of its Group's Annual Contract Quantity (ACQ) and its Group's January Capacity Factor for each capacity assignment period by the scheduled offer date for that capacity assignment period.

PG&E's total adopted core January throughput is: 43,699,915 Dth

The firm pipeline capacity reserved for PG&E's Core End-Use Customers is shown in the table below. From time to time the CPUC may approve new or different pipeline capacities held by PG&E on behalf of Core Customers. To the extent these capacities change, the capacity assignment provisions described herein shall apply to the new capacity holdings.

Pipeline	Capacity
Gas Transmission Northwest	359,968 Dth/d
Foothills Pipe Lines	386,355 GJ/d
NOVA Gas Transmission	390,337 GJ/d
Ruby Pipeline	250,000 Dth/d
El Paso Natural Gas	201,774 Dth/d
Transwestern Pipeline	150,000 Dth/d
PG&E Baja Annual G-AFT (January-December)	348,000 Dth/d
PG&E Baja Seasonal G-SFT (December –February)	321,000 Dth/d
PG&E Redwood Annual G-AFT (January-December)	608,766 Dth/d

(N)

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

Sheet 8

ASSIGNMENT OF FIRM PIPELINE CAPACITY, (Cont'd.):

CTAs must execute a GTSA (Form No. 79-866) and associated exhibits in order to exercise a preferential right to capacity on the PG&E Redwood and Baja Paths. In addition, CTAs, at their option, may execute a GTSA and associated exhibits for additional Backbone pipeline capacity, which will not be offered at the rates specified for Core Procurement Groups in Schedule G-AFT. (T) (T)

For all pipeline capacity, the CTA shall execute an Assignment of Firm Pipeline Capacity (Pipeline Capacity Assignment) (Form 79-845, Attachment C) in order to exercise any preferential right to an assignment of the offered capacity during the applicable capacity assignment period. Within ten (10) business days of PG&E's offer of pipeline capacity for a given capacity assignment period, the CTA shall be required to elect the volume of pipeline capacity that it wishes to take. The CTA may elect different quantities of capacity for each month and for each pipeline. Failure to execute the Pipeline Capacity Assignment by PG&E's stated deadline will result in the CTA losing preferential right to the capacity during the capacity assignment period. Once the capacity assignment is elected by the CTA, the assignment cannot be changed.

The CTA must meet applicable creditworthiness requirements of the Pipelines. The CTA shall assume full responsibility for the applicable Canadian, interstate, and PG&E Backbone pipeline charges for any capacity assigned to the CTA on behalf of Customers of the Group, and shall make payments directly to the applicable pipeline, in accordance with the applicable pipeline filed tariffs.

The CTA will be offered Canadian, interstate, and PG&E Backbone capacity reserved for PG&E's Core End-Use Customers as specified on the schedule below:

Offer Date	Capacity Assignment Period
By January 15**	March – June**
By May 15	July – October
By September 15	November – February

(T)

**To accommodate the CTA Settlement Agreement effective date of April 1, 2012, the first pipeline capacity offer will be for three (3) months, instead of four (4) months, and will take place by February 15 for April 2012 – June 2012. Subsequent offers will follow the schedule above. (T)

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

FIRM WINTER CAPACITY REQUIREMENT:

As a condition of a CTA providing gas aggregation services to Customers in a Group, during the Winter Season, November 1 through March 31, CTAs are required to meet the Firm Winter Capacity Requirement as specified below. The Firm Winter Capacity Requirement requires that the CTA contract for firm Backbone pipeline capacity or firm PG&E storage capacity and withdrawal rights equal to the Group's pro rata share of firm Backbone pipeline capacity PG&E has reserved for Core End-Use Customers.

The CTA may satisfy such Firm Winter Capacity Requirement in any combination of the following:

1. Under the terms of Schedules G-SFT or G-AFT, contract with PG&E for all or part of the CTA's path-specific proportionate share of firm Backbone pipeline capacity PG&E has reserved for Core End-Use Customers.

2. Contract with a party other than PG&E for guaranteed use of that party's firm Backbone pipeline capacity or for guaranteed use of that party's firm PG&E storage capacity and withdrawal rights in conjunction with Mission Path capacity under Schedules G-AA or G-NAA. (T)

3. Contract with PG&E for firm Backbone pipeline capacity or firm storage capacity and withdrawal rights in conjunction with Mission Path capacity under Schedules G-AA or G-NAA. (T)

Capacity held to satisfy core firm storage requirements may not simultaneously be used to satisfy the Firm Winter Capacity requirement.

Should the CTA exercise Option 2 or 3 above to satisfy the Firm Winter Capacity requirements for any winter month, the CTA shall be required to submit, within five (5) days of notification, an executed Declaration of Alternate Winter Capacity (Form No. 79-845, Attachment J).

If a CTA has fulfilled this Firm Winter Capacity Requirement and has A) incurred no instances of non-compliance with an Emergency Flow Order (EFO), and B) no more than one (1) such instance with a Low Inventory Operational Flow Order (OFO) as specified in Rule 14 for a two-year period, the CTA will no longer be required to meet this Firm Winter Capacity Requirement provided that the Firm Winter Capacity Requirement (T) shall be reinstated for any CTA that subsequently fails to meet the requirements set forth (T) in A) and B) of this paragraph. (T)

ASSIGNMENT OF CORE FIRM STORAGE:

On an annual basis, PG&E will determine for each Group a core firm storage allocation consisting of core firm inventory capacity and associated injection and withdrawal capacity (Initial Storage Allocation). The Initial Storage Allocation will be provided and adjusted by a Mid-Year Storage Allocation Adjustment, as described in the next section below. The Initial Storage Allocation and Mid-Year Storage Allocation Adjustment will be based on a pro rata share of PG&E's total core firm storage capacity reservation and will be calculated as described below.

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

Sheet 10

ASSIGNMENT OF CORE FIRM STORAGE, (Cont'd.):

By February 15 of each year, PG&E will calculate each Group's Initial Storage Allocation for the upcoming storage year of April 1 through March 31 (Storage Year) based upon the Customers in the Group for April of that year using the DASRs that have been processed to date, and PG&E will offer that storage capacity to the CTA. Within ten (10) business days of PG&E's offer, each CTA may, at its option, reject all or part of its Initial Storage Allocation. A CTA's failure to reject its Initial Storage Allocation by this deadline shall be deemed an acceptance thereof. (T)

Each CTA's assigned core firm storage capacity (Assigned Storage) shall be the sum of capacity offered and accepted by the CTA in the Initial Storage Allocation and Mid-Year Storage Allocation Adjustment. Assigned Storage will be provided under the terms of Schedule G-CFS.

Each CTA will be required to execute and shall be subject to the terms and conditions of a Core Firm Storage Declarations (Form No. 79-845, Attachment D) with PG&E, for its Assigned Storage. The rejected percentage shall also be specified in Attachment D. In the event the CTA rejects a portion of its Initial Storage Allocation, it must do so in increments of 10 percent (10%), (e.g., 10%, 20%, 30%, and so forth) up to 100 percent. When storage allocation amounts are rejected, the CTA must certify Alternate Resources for each Winter month in amounts equivalent to the rejected withdrawal capacity, as more fully set forth elsewhere in this rate schedule. Gas in storage, for the purpose of providing core reliability, including gas stored using the Assigned Storage, may not incur encumbrances of any kind.

PG&E's determination of the core firm storage capacity allocation for each Group will be based on the sum of the historical Winter Season gas usage for the Customers in the Group, unless otherwise agreed upon.

PG&E's total core storage capacity reservations, by subfunction, are:

Annual Inventory	33,478 MDth
Average Daily Injection	157 MDth/day
Average Daily Withdrawal	1,111 MDth/day

To determine each Groups's allocation, PG&E will calculate the ratio of the Group's Winter Season Usage to PG&E's total core Winter Season forecast throughput, as adopted in PG&E's latest Cost Allocation Proceeding (CAP). This ratio, expressed as a percentage, will then be multiplied by the Annual Inventory above to determine the amount of inventory that will be allocated to the CTA. For CTAs whose Assigned Storage inventory is up to 1,000 MDth, the percentage will also be applied to the Average Daily Injection and Average Daily Withdrawal to determine the daily injection and withdrawal limits. For CTAs whose Assigned Storage inventory is greater than 1,000 MDth, the injection and withdrawal capacities will be variable. The calculations for those injection and withdrawal capacities are specified in Schedule G-CFS.

PG&E's total adopted core Winter Season throughput is: 177,032,109 Dth

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

MID-YEAR CORE FIRM STORAGE ALLOCATION ADJUSTMENT: (N)

By August 15 of each year, PG&E will provide to the CTAs recalculated CTA storage allocations based upon the Customers in the Group for November of that year using the DASRs that have been processed to date. This recalculated storage allocation (Mid-Year Storage Allocation) will be compared to the Initial Storage Allocation for the current storage season for purposes of making the Mid-Year Storage Allocation Adjustment.

Increase In Load: If the Mid-Year Storage Allocation exceeds the Initial Storage Allocation by more than 10,000 decatherms, the CTA will have the option to accept an additional core storage allocation for the full amount or a portion of the increase, in ten percent (10%) increments to the extent capacity is available. Any such election must be provided by the CTA to PG&E within ten (10) business days of PG&E's communication of the recalculated CTA storage allocation. The resulting storage allocation adjustment, will be added to the CTA's Assigned Storage effective September 1. If the Mid-Year Storage Allocation exceeds the Initial Storage Allocation by 10,000 decatherms or less, the Assigned Storage will remain unchanged.

A CTA's failure to reject its Mid-Year Storage Allocation Adjustment by the deadline set by PG&E shall be deemed an acceptance thereof. For the amount of this increase in Assigned Storage, gas in PG&E's Core Gas Supply Department's storage account will be transferred to the CTA core firm storage account at a price and in the amounts specified in Schedule G-CFS.

PG&E's offer of additional storage capacity at Mid-Year will be contingent on the availability of storage capacity. As described below, there will be an auction of storage capacity following the initial offer and assignment of annual core firm storage. Capacity sold at this auction, whether to CTAs or to other parties, will not be available to offer to CTAs at the Mid-Year Adjustment. Similarly, left-over capacity retained by PG&E's Core Gas Supply Department for $0.01/Dth/month, as described below, will not be available to offer to CTAs at Mid-Year. CTAs that are eligible for an increase in storage capacity at Mid-Year will be offered that capacity only to the extent that PG&E's Core Gas Supply Department and/or other CTAs (that accepted their Initial Storage Allocations) have experienced a decrease in load sufficient to require them to relinquish storage capacity.

Decrease In Load: If the Mid-Year Storage Allocation is less than the Initial Storage Allocation by more than 10,000 decatherms, and the CTA has Assigned Storage, the CTA must accept a proportional reduction in its Assigned Storage. In such event, the CTA shall transfer to PG&E's Core Gas Supply Department a share of the decrease equal to the proportion obtained by dividing the CTA's Assigned Storage by its Initial Storage Allocation. For example, a CTA that accepted an assignment of 70% of its Initial Storage Allocation must transfer 70% of the difference between its Initial Storage Allocation and the Mid-Year Storage Allocation Adjustment. If the Mid-Year Storage Allocation results in a decrease of 10,000 decatherms or less, the Assigned Storage will remain unchanged.

For the amount of this reduction in Assigned Storage, gas in the CTA's core firm storage account will be transferred to PG&E Core Gas Supply Department's storage account at a price and in the amounts specified in Schedule G-CFS. (N)

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

ASSIGNED STORAGE PAYMENTS: For those months during which the CTA holds Assigned Storage, the CTA will pay a monthly charge equal to the inventory volume associated with its Assigned Storage, multiplied by the monthly charge specified in Schedule G-CFS for the applicable month. (N)

The CTA will pay the same rates that PG&E's Core Gas Supply Department pays for the capacity as well as any other applicable rates, fees, and charges.

ALTERNATE RESOURCES AND CTA CERTIFICATION: For storage withdrawal capacity rejected by a CTA in the Initial Storage Allocation or Mid-Year Storage Allocation, Alternate Resources, in like amounts, will be required as provided below. On a monthly basis, during the Winter Season, CTAs shall submit an executed Certification of Alternate Resources for Rejected Storage Withdrawal Capacity (Form No. 79-845, Attachment I). The CTA must provide such certification to PG&E as specified by PG&E. PG&E will not require these certifications earlier than ten business days prior to the beginning of each Winter month.

Certified Alternate Resources may not duplicate any resources offered as replacements for firm winter Backbone capacity that the CTA may be required to hold. The CTA must satisfy the Alternative Resources obligation with any combination of the following:

1. Contracted firm storage services from PG&E or from an on-system CPUC-certified independent storage provider; and/or

2. Contracted firm PG&E Backbone capacity matched with an equivalent volume of contracted upstream gas supply, plus any necessary firm upstream pipeline capacity (upstream gas supply may include a gas producer contract, or a contract with an off-system CPUC-certified, gas utility or independent storage provider); and/or

3. Third-party peaking supply arrangements, where that supply is backed up by contracts, as specified in 1 or 2, above.

RELEASE AND INDEMNIFICATION OF PG&E: For any rejection of the Initial Storage Allocation or the Mid-Year Storage Allocation to be effective, the CTA shall sign and deliver to PG&E a Core Firm Storage Declarations (Form 79-845, Attachment D). This form shall release PG&E from liability associated with that CTA's rejection of storage assets, as well as indemnify PG&E for losses that arise: (i) from any representation in the CTA's monthly Alternate Resources certifications which turns out to be inaccurate, or (ii) from any failure of the CTAs Alternate Resources to perform. (N)

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

COST RESPONSIBILITY FOR CTA-REJECTED FIRM PIPELINE CAPACITY AND FIRM STORAGE INVENTORY CAPACITY:

There will be a three-year period (Transition Period) during which PG&E's Core Gas Supply Department will be obligated to retain and pay for a decreasing share of any firm pipeline capacity or firm storage inventory capacity offered to but rejected by CTAs (CTA-Rejected Capacity), and the CTAs will take increasing cost responsibility for such rejected capacity. By the end of the Transition Period, the CTAs will take full cost responsibility for such capacity. The maximum aggregate amount (as a percentage of the total Core capacity holding and applied to annual storage and individually to each pipeline for each month) of the rejected capacity that PG&E's Core Gas Supply Department will be obligated to retain is shown in the table below: (N)

Transition Period Years	Maximum Percentage
April 2012 – March 2013	12%
April 2013 – March 2014	7%
April 2014 – March 2015	4%
Post March 2015	0%

Any firm pipeline and storage capacity rejected by the CTAs in aggregate in excess of the above amounts will remain the cost responsibility of the CTAs.

April 2015 onward is designated the "Post-Transition Period," during which CTAs will assume full cost responsibility for all rejected firm pipeline capacity and rejected firm storage inventory capacity.

In order to mitigate the costs borne by CTAs for capacity rejected by them and not retained by PG&E's Core Gas Supply Department, PG&E will, as a service to CTAs, offer such capacity to the market and will credit the capacity release proceeds against the costs otherwise owed to PG&E by the CTAs. The capacity release process is described in the next section.

Any CTA-Rejected Capacity costs remaining after PG&E's Core Gas Supply Department has retained a portion of such capacity, as described above, and PG&E has attempted to release such capacity, as described in the next section, will be allocated to and invoiced to the CTAs in proportion to the amount of capacity rejected by each CTA. This allocation will be performed on a pipeline-by-pipeline, month-by-month basis. CTA-Rejected Capacity costs arising from capacity offered to, but rejected by, a particular CTA during the Mid-Year Core Firm Storage Allocation Adjustment will be invoiced directly to that CTA except for the reservation rate of one penny per decatherm per month ($0.01/Dth/month) paid by PG&E's Core Gas Supply Department, as described in the next section. (N)

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

TREATMENT OF CTA-REJECTED FIRM PIPELINE CAPACITY AND FIRM STORAGE INVENTORY CAPACITY:

PG&E's Core Gas Supply Department will retain and take cost responsibility for a portion of the aggregate CTA-Rejected Capacity during the transition period, as described above. PG&E will manage the remaining CTA-Rejected Capacity (Net CTA-Rejected Capacity) in the following manner: PG&E will attempt to release the Net CTA-Rejected Capacity to the marketplace through an auction, bulletin board listing or similar process. As PG&E will have very little discretion in how this capacity will be resold, a CTA cannot protest the results of that process. To the extent left-over capacity remains after the capacity release process, PG&E's Core Gas Supply Department will retain this left-over capacity at the rate described below. (N)

PG&E will, as a service to CTAs, offer the Net CTA-Rejected Capacity to the marketplace prior to each capacity assignment period, that is, three times per year for Pipeline capacity and once per year for storage capacity. For Pipeline capacity, PG&E will also offer Net CTA-Rejected Capacity once per month during each capacity assignment period to the extent capacity remains available. In offering capacity for release, PG&E will abide by the established capacity release procedures and applicable tariff provisions of the various Pipelines on which the rejected capacity is released. To the extent these procedures and requirements change, PG&E will adjust its procedures for the release of rejected capacity as may be appropriate.

PG&E will offer Pipeline capacity on the following basis:

1. Only single-month, single-Pipeline contracts through the end of the current capacity assignment period will be offered. Contracts for multiple Pipelines, multiple products (transmission and storage service), or multiple months will not be bundled together.

2. Any reservation rate bid greater than zero will be acceptable.

3. The minimum acceptable bid quantity will be the lesser of (i) one thousand (1,000) Dth/d, or (ii) the total capacity offered for that month on that Pipeline.

4. All applicable Pipeline tariff rates and fees other than the reservation rate will continue to apply, and will be the responsibility of the assignee.

5. Pipeline contracts will be awarded for each month based upon the reservation rate--highest rate first, lowest rate last. In the event there are two or more bids of equal value for a combined contract quantity greater than the remaining available capacity on a given pipeline, the bidders will each be awarded a pro rata amount of the remaining available capacity for that month.

6. Bidders must satisfy all applicable creditworthiness requirements of the Pipeline(s) on which they are bidding for capacity. (N)

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

TREATMENT OF CTA-REJECTED FIRM PIPELINE CAPACITY AND FIRM STORAGE INVENTORY CAPACITY (Cont'd):

To the extent Net CTA-Rejected Capacity remains unassigned after the initial auction of Pipeline capacity prior to each capacity assignment period, PG&E's Core Gas Supply Department will be deemed to have bid a reservation rate of one penny per decatherm per month ($0.01/Dth/month) for such capacity. This deemed bid shall apply only to the first month of the Pipeline capacity assignment period, that is, to the capacity for use during the next immediate month. To the extent Net CTA-Rejected Capacity remains unassigned after each subsequent monthly Pipeline capacity auction during the capacity assignment period, PG&E's Core Gas Supply Department will similarly be deemed to have bid a reservation rate of $0.01/Dth/month for such capacity, but only for the first month that capacity is offered in each auction.

PG&E's Core Gas Supply Department will retain these unassigned Pipeline capacity amounts in its contracts with the various Pipelines, and will have rights to use and/or release this capacity in the same manner as its other capacity holdings. The $0.01/Dth/month effective reservation rate will be credited against the costs otherwise owed by the CTAs to PG&E in the same manner as the auction proceeds. The CTAs will be responsible for all other reservation costs associated with these Pipeline capacities, other than the $0.01/Dth/month rate.

PG&E will offer storage capacity to the marketplace once a year, prior to the start of the annual Storage Year (April - March). PG&E will not offer rejected storage capacity to the market following the Mid-Year Storage Allocation Adjustment or at any other time. PG&E will offer storage capacity on the following basis: (T)

1. Only 12-month bids will be acceptable. Contracts for multiple products (transmission and storage service) on one or more pipelines may not be bundled together.

2. Any reservation rate greater than zero will be acceptable.

3. The minimum acceptable bid quantity will be the lesser of (i) ten thousand (10,000) Dth of inventory plus associated injection and withdrawal rights, or (ii) the total storage capacity offered.

4. Injection and withdrawal rights will be allocated in the proportions indicated earlier under Assignment Of Core Firm Storage.

5. Storage contracts will be awarded for the entire storage year based upon the reservation rate: highest rate first, lowest rate last. In the event there are two or more bids of equal value for a combined contract quantity greater than the available storage capacity at a given price, the bidders will each be awarded a pro rata amount of the available storage capacity.

6. Bidders must satisfy all applicable creditworthiness requirements for the awarded storage capacity specified in PG&E's Tariffs.

(Continued)

GAS SCHEDULE G-CT
CORE GAS AGGREGATION SERVICE

TREATMENT OF CTA-REJECTED FIRM PIPELINE CAPACITY AND FIRM STORAGE INVENTORY CAPACITY (Cont'd):

To the extent Net CTA-Rejected Capacity remains unassigned after the initial auction of Storage capacity prior to the annual capacity assignment period, PG&E's Core Gas Supply Department will be deemed to have bid a reservation rate of one penny per decatherm per month ($0.01/Dth/month) for such capacity. This deemed bid shall apply to the entire 12-month Storage capacity assignment period. Further, to the extent additional Net CTA-Rejected Capacity remains after the Mid-Year Allocation Adjustment, PG&E's Core Gas Supply Department will similarly be deemed to have bid a reservation rate of $0.01/Dth/month for such capacity for the remaining months in the storage year.

PG&E's Core Gas Supply Department will retain these unassigned capacity amounts in its Storage contract, and will have rights to use such capacity in the same manner as its other Storage capacity holdings. The $0.01/Dth/month effective reservation rate will be credited against the costs otherwise owed by the CTAs to PG&E in the same manner as the auction proceeds. The CTAs will be responsible for all other reservation costs associated with this Storage capacity, other than the $0.01/Dth/month rate.

ASSIGNMENT: (D)

PG&E Backbone pipeline capacity or storage capacity allocation accepted under this schedule, including associated rights and obligations, may be assigned by a CTA, subject to PG&E's creditworthiness requirements. (N)

Storage allocation accepted under this schedule can only be assigned prior to the start of the Storage Year and may not be reassigned after this initial assignment by a CTA. Any storage capacity assignment will be for the entire Storage Year. Injection and withdrawal rights will be assigned in proportion to the assigned storage capacity. The assignee of storage capacity allocation accepted under this schedule will not be subject to minimum gas inventory requirements.

For PG&E Backbone pipeline capacity or storage capacity allocation accepted under this schedule and subsequently assigned, CTAs shall provide Alternate Resources during the winter months as prescribed in the "Firm Winter Capacity Requirement" and "Alternate Resources And CTA Certification" sections of this schedule. (N)

NOMINATIONS: Nominations are required from the CTA, on behalf of the Group, as specified in Rule 21.

BALANCING SERVICE: Service hereunder shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL.

BILLING/ PAYMENT: Rule 23 and Rule 25 provide the terms and conditions of billing and payment procedures under this schedule.

CREDIT-WORTHINESS: Customers must meet PG&E's creditworthiness standards as set forth in Rules 6 and 7. Customers who have established credit with PG&E will not be required to pay an additional or new deposit to be eligible for service under this schedule.

The CTA must meet the requirements specified in Rule 23 and Rule 25 before it may provide gas aggregation services under this schedule.

SUPPORTING DOCUMENTS FOR
DIRECT TESTIMONY OF MICHAEL BROWN

Exhibit 14

Expert Report on Issues Affecting Small Businesses

Testimony of Michael Brown

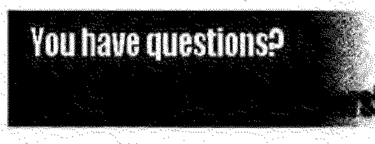
on behalf of
Small Business Utility Advocates
548 Market Street, Suite 11200
San Francisco, CA 94104
Tel: 415-602-6223 Fax: 415-789-4556

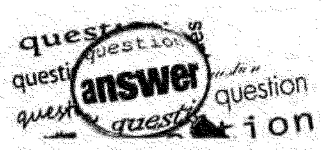
California Public Utilities Commission
Application 12-11-009
May 16, 2013

TIGER

INFO@TIGERNATURALGAS.COM
1.888.875.6122

[Back to California FAQ's]





Service Requirements: The PG&E service area is open to ALL Residential and Commercial Customers for Natural Gas.

#aI didn't think I had a choice of who I could buy my natural gas from. How does this work?

You certainly do have a choice. The natural gas industry in your area has been deregulated. The easiest way to understand it is to think of it like telecommunications deregulation, but instead of using phone lines we are using natural gas lines. We are able to sell you your natural gas at a discount and you continue to use the utilities existing pipelines to transport the natural gas to your facility or residence. There are no setup fees or connection fees and your utility will not charge you additional transportation costs. So we are able to pass on the savings from the actual natural gas you use.

How can Tiger be able to offer me a lower rate than my utility?

The utility is allowed to build in cost of their infrastructure, Bad Debts and anything else the Public Utilities Commission will allow them, into their actual cost of gas. Tiger has minimal overhead and is much more flexible and able to go out and get the best price for our natural gas. We then pass savings on to our customers.

How are you able to get the natural gas to me?

We will give the natural gas you buy from us directly to you utility company and then you will still pay them to transmit and distribute the natural gas through their existing pipelines to your residence or facility. So you will still

SEARCH TIGER

SEARCH

PG&E CUSTOMERS

Save 9-15%* year after year ...

Are you requesting a quote for commercial or residential? *

○ Residential
○ Commercial

Name *

Phone *

Email *

Local Utility *

SUBMIT

be a customer of your utility but if you get your natural gas from Tiger you will still save money annually overall when you add in their transportation charges and the savings we offer you on the natural gas.

What if I have an emergency?

If you have an emergency like a gas leak or a fire you will still call your local utility company and they will come out and service your pipelines and meters, you will still be their customer because you will pay them to distribute your natural gas to your residence or facility. They will not charge you more in a maintenance or emergency situation because you are a Tiger customer. However, if you have a billing or customer service issue you can quickly contact your Tiger representative and be taken care of much quicker and effectively.

What are the risks involved with switching?

There is essentially no additional risk. Tiger has been in business for over 19 years and has over 25,000 commercial accounts nationwide and we have never received a better business bureau complaint. That is not the case with other energy marketers. At Tiger we are truly devoted to customer satisfaction and our company was founded on the principles of integrity, reliability, and trust. We have survived and outlasted many others in our industry even when most have only been in business a fraction of the time we have. We will be here for a long time to come and in the event we cannot supply you with gas your local utility company would begin to supply you again automatically. That is something that has never once happened in our 19 years of business. Look us up on the Better Business Bureau website (BBB.org). We have been in business since 1991 and have over 25,000 accounts nationwide without ever receiving one complaint. This is because Tiger's strong emphasis on maintaining superior customer service and customer relationships are key elements to our success.

How will you bill me for the natural gas we use?

If you are a Residential Tiger Customer you will continue to just receive your one PG&E bill. The only difference will be that instead of having PG&E's cost for your natural gas on your bill you would have Tigers. Nothing will change from your prospective and you just pay once using any current method available to you from PG&E. There is a $.05 per day customer fee included as well.

If you are a Commercial Tiger Customer in the PG&E area you would be eligible to receive your charges attached to your current PG&E bill, just as outlined above. You would also have the option to receive a separate bill from Tiger for the natural gas you used. This option has no customer fee.

Is there a chance that Tiger would cost me more overall than my Utility?

In some months there is a chance that we could cost you more but that does not happen often. However, when you look at it on an annual basis we have never cost our customers more than the utility would have on a per Therm basis. The reason that Tigers price can sometimes be more than the utilities price is because the utility actually lags behind were the current market price is. Historically our prices on a monthly level are most always less than the utilities but when natural gas prices rise unexpectedly and quickly in a matter of a few months it can result in our price for a month being more than the utilities. This is because when we were buying our gas at the markets current rates the utility was still selling gas at rates below where the current market was. This is because they must set their monthly prices well in advance of when we do and the market was not forecasted to rise so much or so quickly. This results in their prices continuing to rise as ours level off or drop from their highs. That is why we like for our customers to look at the savings on an annual basis. Essentially, if their prices are less than ours in one month then that difference is likely to be made up in subsequent months.

What about the transportation cost of my natural gas service?

Your Utility will still charge you for the transportation of the natural gas to your facility or residence. You are already paying them for the transportation of the gas right now and when you become our customer your utility will not charge you anything additional for the transportation. So you can take the transportation out of the equation and whatever we can save you on the natural gas is what you can expect to save overall. You must use Natural Gas to save money with this program, the more you use the more we can save you.

Can I be your customer and participate in this program while receiving rebates and other savings program incentives through my utility?

Yes, you can purchase your Natural Gas at a discount from us and still be eligible for all the savings and rebate programs your utilities offer. This even includes California's CARE customers. Even if you signed a contract for a rebate you will remain a customer of your utility and still be eligible for the rebate and be able to participate in our program.

How is my index rate price actually determined each month?

In California the index's we use to determine your price each month is either the Natural Gas Intelligence (NGI) or Inside FERC (IF) index. These indexes are third party organizations that look at all the transactions happening at a particular geographical delivery point and assign an index value for that delivery point each month. Both of these indexes are independent third party organizations, are highly respected and industry standards in the areas we use them. Essentially, they are determining the market based rate for your area each month.

WHY TIGER?

Why do over 23,000 Customers choose Tiger?

- Proven performance
- Cost savings
- Customer service
- 20 years in business
- Minority-owned business
- A+ BBB Rating

"Tiger's dedication to customers has resulted in customers being loyal to Tiger. Going out of the way to make certain customers are satisfied has earned Tiger Natural Gas the reputation of dependability."

Ralph Schaefer, Managing Editor
Tulsa Business Journal

PG&E'S CORE GAS AGGREGATION PROGRAM – FREQUENTLY ASKED QUESTIONS

(This information is taken directly from the PG&E Website and Tariff)

What is Core Gas Aggregation Service?

Core Gas Aggregation Service is an optional service that allows core customers to purchase gas directly from competitive suppliers, rather than from PG&E. Core customers are defined as all residential and small commercial customers. Under this gas rate option, customers purchase their gas commodity from a competitive supplier, known as a Core Transport Agent (CTA) and continue to use PG&E for gas transportation. PG&E still owns and maintains the lines that deliver the gas to your home or business under this service.

Why is PG&E offering this service?

PG&E believes that all customers benefit from additional choices in the marketplace. Providing choices creates competition among energy suppliers and increases value for customers. Suppliers can often provide customers with price protection, alternative billing methods and cost savings.

Regardless of what choices you make, your other gas services will be unchanged. PG&E remains committed to the safe and reliable delivery of natural gas to your home or business, and remains your first point of contact for safety issues regarding gas service.

Who is eligible to participate in the program?

Residential and small commercial customers currently being billed for gas on any core gas rate schedule.

Are CTAs regulated?

CTAs are not regulated by the California Public Utilities Commission (CPUC) or PG&E. However, PG&E requires new CTAs to enter into a Core Gas Aggregation Service Agreement with PG&E which outlines the CTAs' obligations and responsibilities. PG&E then requires all new CTAs to complete a certification process, which entails meeting credit and technical requirements, before they are eligible to enroll and serve customers.

How does the program work?

To participate, your home or business must be part of a gas usage pool with a combined usage of at least 120,000 therms per year. The pool can consist of any combination of core gas customers from within PG&E's service territory and need not be linked by residential or business class, or geography. Linked by their designation of a common CTA, each customer in the pool is required to make a minimum 12-month commitment to the Core Gas Aggregation Program and purchase natural gas from a CTA, instead of PG&E.

What are the responsibilities of my new supplier?

A CTA is responsible for ensuring that sufficient gas is delivered daily to PG&E's pipeline system to supply its customers' forecasted usage. As part of PG&E's ongoing service, PG&E is the backup supplier in the event your CTA fails to arrange for an adequate supply of natural gas, defaults on its obligations or goes out of business.

Will I continue to receive a monthly bill from PG&E?

Yes, in most cases. PG&E provides three types of billing options for a CTA: 1) PG&E Consolidated Billing where PG&E consolidates its monthly gas distribution and transmission charges and a CTA's gas charges into a single bill; 2) CTA Consolidated Billing where a CTA consolidates its monthly charges and PG&E's charges into a single bill; and 3) Separate Billing where PG&E and a CTA separately bill for their respective monthly charges.

Who do I contact for billing questions?

Contact PG&E for questions regarding the gas distribution and transmission charges shown on your monthly bill. Contact your CTA for any questions concerning their monthly gas charges.

Will I continue to receive my CARE discount if I buy gas from a CTA?

Yes. The California Alternate Rates for Energy (CARE) discount is mandated by the State of California and continues for all qualified customers regardless of whether PG&E or a CTA supplies their gas. The CARE discount for the customer's gas commodity, distribution and transmission charges will continue to appear on the PG&E portion of the bill and the discount would be the same as if the customer remained a bundled customer with PG&E.

Will PG&E lose money if I switch to a CTA?

No. Due to the way natural gas utilities are regulated, PG&E does not make a profit from the sale of natural gas to its retail customers. PG&E instead makes its regulated profit from delivering gas through its pipeline system, as well as from other sources.

Are there any extra charges or franchise fee surcharges

PG&E does not assess any "extra" charges to customers who purchase natural gas from a CTA. Under any of the billing options available to a CTA (e.g., PG&E Consolidated Billing, CTA Consolidated Billing, and Separate Billing), a customer's bill is first calculated as if the customer remained on bundled service with PG&E. The PG&E procurement (gas) portion of the bill is then subtracted from the bill through a "Procurement Credit." Finally, a franchise fee is added to the PG&E portion of the bill. Please note that the franchise fee is NOT an extra charge for customers buying their gas from a CTA—it is part of the PG&E procurement charge and is collected under Gas Schedule G-SUR to pay franchise fees (roughly 1 percent) on the gas volumes purchased from a CTA.

If I buy my gas from a CTA, whom do I call in case of an emergency?

You should continue to call PG&E in case of any emergency involving gas service to your home or business. We will also continue to respond to your safety-related calls, such as gas leaks, and maintain the distribution system leading to your home. PG&E can be reached at 1-800-743-5000.

If I choose a different supplier, will the gas be different?

No. The quality of the natural gas provided to you is the same high quality gas you would otherwise receive.

918.491.6998
1.888.875.6122
info@tigernaturalgas.com
1422 East 71st Street
Tulsa, OK 74136-5060

SUPPORTING DOCUMENTS FOR
DIRECT TESTIMONY OF MICHAEL BROWN

Exhibit 15

Expert Report on Issues Affecting Small Businesses

Testimony of Michael Brown

on behalf of
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California Public Utilities Commission
Application 12-11-009
May 16, 2013

Forever Stamp Fact Sheet

- The first Forever Stamp went on sale in April 2007 and it featured an image of the Liberty Bell. In 2011, all first-class one ounce stamps became forever stamps with the exception of stamps in coils of 500, 3,000, and 10,000.
- As the name suggests, Forever Stamps can be used to mail a one-ounce letter regardless of when the stamps are purchased or used and no matter how prices may change in the future.
- Forever Stamps are always sold at the same price as a regular First-Class Mail stamp. Forever Stamps are currently being sold for 45 cents and will be sold for 46 cents beginning January 27, 2013.
- The Postal Service developed the Forever Stamp for consumers ease of use during price changes. Forever Stamps are available for purchase at post offices nationwide, online at usps.com, and by phone at 1-800-STAMP-24 (1-800-782-6724). They are sold in sheets and booklets of 20.
- Customers can use Forever Stamps for international mail, but since all international prices are higher than domestic prices, customers will need to attach additional postage. The value of the Forever Stamp is the domestic First-Class Mail letter price in effect on the day of use.

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Please Note: For broadcast quality video and audio, photo stills and other media resources, visit the USPS Newsroom at www.usps.com/news.

An independent federal agency, the U.S. Postal Service is the only delivery service that visits every address in the nation, 146 million homes and businesses, six days a week. It has 37,000 retail locations and relies on the sale of postage, products, and services to pay for operating expenses, not tax dollars. The Postal Service has annual revenues of $75 billion and delivers nearly half the world's mail.

Download Adobe Acrobat Reader

SUPPORTING DOCUMENTS FOR
DIRECT TESTIMONY OF MICHAEL BROWN

Exhibit 16

Expert Report on Issues Affecting Small Businesses

Testimony of Michael Brown

on behalf of
Small Business Utility Advocates
548 Market Street, Suite 11200
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Tel: 415-602-6223 Fax: 415-789-4556

California Public Utilities Commission
Application 12-11-009
May 16, 2013

COST OF AB 32 ON CALIFORNIA SMALL BUSINESSES—SUMMARY REPORT OF FINDINGS

Submitted to:

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California Small Business Roundtable

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June 2009

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COST OF AB 32 ON CALIFORNIA SMALL BUSINESSES—SUMMARY REPORT OF FINDINGS

EXECUTIVE SUMMARY

PURPOSE OF THE STUDY

The objective of this research is to describe the impact and cost of AB 32 on California small businesses. Previous studies document the cost of federal regulations on small businesses. The purpose of this study is to identify and establish the various impacts and cost of the AB 32 burden on small business in California and to assess the extent to which this disadvantages small business. This cost is in addition to the cost of federal regulation or state regulation that is widely documented by previously published studies.

Issues addressed in this study include:

- What is the impact of the additional costs associated with implementing AB 32 on the state's economy and on consumers?

- What is the impact of the additional costs associated with implementing AB 32 on small businesses in California?

- How does the cost of AB 32 impact selected industries and economic sectors of California's economy?

METHODOLOGY

IMPLAN was used to compute the overall impact, and a specially designed feeder input model were created to provide input to the IMPLAN model that was used for various scenarios described later in this Summary Report.

The total direct, indirect, and induced costs arising due to the multiplier effect are presented in four ways:

- ***Output*** accounts for total revenues lost including all sources of income for a given time period for an industry in dollars. This is the best overall measure of business and economic activity because it is the measure most firms use to determine current activity levels.

- ***Employment*** demonstrates the number of jobs not generated and is calculated in a full-time equivalent employment value on an annual basis.

- ***Indirect Business Taxes*** consist of property taxes, excise taxes, fees, licenses, and sales taxes that would have been paid by businesses but now lost. While all taxes during the normal operation of bussinesses are included, taxes on profits or income are not included.

- ***Labor Income*** includes all forms of employee compensation that would have been paid by employers but now lost (e.g., total payroll costs including benefits, wages and salaries of workers, health and life insurance, retirement payments, non-cash compensation), and proprietary income (e.g., self employment income, income received by private business owners including doctors, laywers).

To provide data for the IMPLAN analysis, the analysts developed a "feeder" economic model that specifically addresses the variables. This model not only provides the data used in the IMPLAN analysis, but allows for a consideration of the impacts at the consumer level.

Costs of AB 32 Used in the Computations

As previously indicated, there is some uncertainty as to what the actual costs of AB 32 will be. Even the ARB in its Scoping Plan indicated that it was using "…estimated costs and savings … as model inputs for individual measures.'[1] Furthermore, it indicated that "The level of detail on the costs and savings for the different measures included in the Scoping Plan vary widely. Because some of the measures are in the later stages of regulatory development, their costs and savings estimates were readily available. For other measures, the costs and savings were specifically estimated for the Scoping Plan. Many of these estimates are preliminary, and are likely to change during the regulatory process."[2]

Given the extended time frame and complexity of this Act, some degree of estimation is to be expected. Accordingly, it was deemed appropriate to use three approaches for estimating the economic impact of AB 32 on California's economy. One focuses on the minimum impact using the costs that were identified by ARB, another based on the anticipated costs to California consumers and/or businesses, and the third based on the anticipated costs to California small businesses.

Scenario One: Minimum Impact

According to the ARB, the annualized cost of implementing AB 32 is $24.878 billion.[3] As previously indicated, various analysts believe that there are considerably more costs associated with AB 32 that either were deliberately not taken into account in the ARB

[1] ARB, "Climate Change Scoping Plan," December 2008, p. 73.
[2] ARB, "Climate Change Scoping Plan Appendices, Volume II," December 2008, p. G-I-1.
[3] ARB, "Climate Change Scoping Plan Appendices, Volume II," December 2008, p. G-I-8.

analysis or are "hidden costs" that were not acknowledged by ARB. The economic analysis completed by ARB fails to address several key economic issues and variables or the uncertainty surrounding their costs. Examples include:

- Costs or disruptions to prices of crops arising due to changes in land use.
- Costs of reporting, monitoring, and enforcing compliance.
- Future availability of alternative fuels or any major fluctuations or disruptions in the demand supply equation and resulting prices.
- Availability of vehicles utilizing alternative fuels, and costs associated with technology advancements needed to make the vehicles commercially affordable and reasonably priced.
- The cost of financing of the new production facilities, or of the required investments for both production and distribution.
- Volatility in forecasts of prices of crude, gasoline, and diesel.
- Research and development costs for lower carbon intensity alternative transportation fuels.

Initial estimates suggest that billions of dollars of costs will result from the implementation of AB 32. In addition to the costs suggested by ARB, others include infrastructure and capital investment costs upward of $60 billion, $5 billion for new home construction, $36 billion for more fuel-efficient cars, and billions in higher food costs due to higher transportation costs and change in land use. In summary, the implementation costs of AB 32 could easily exceed $100 billion upfront.

Given the uncertainty of costs and greater uncertainty surrounding the suggested benefits or savings that may never be realized, the $24.878 billion cost was used for computational purposes as the minimum cost scenario. As indicated by the LAO, the scoping plan "includes an inconsistent and incomplete evaluation of the costs and savings associated with its recommendations."[4] Therefore, it is likely that this cost is the minimum that will be incurred by businesses and consumers. As previously indicated, the savings identified by ARB are considered too speculative to consider at this time, in part because the outcomes are uncertain and the savings require major investments by businesses and/or consumers that might not be possible.

Scenario Two: Expected Impact to Consumers

The expected economic costs of implementing AB 32 are based on the costs that are projected to be incurred by California consumers. This is predicated on the assumption that the costs to businesses will be shifted through the delivery chain to their customers. Ultimately, therefore, they will reside with consumers. Even if these costs are not or

[4]Letter to the Honorable Roger Niello dated December 12, 2008 from Mr. Mac Taylor, Legislative Analyst, p. 12.

cannot be passed down the delivery chain, they will be incurred and absorbed by businesses. In essence, they will be costs to customers or lost profits to businesses, which will impede their abilities to survive and grow. Given that businesses may not be able to pass down all the increased costs to final consumers, estimates of costs to consumers are likely conservatively stated.

Based on these five increases alone, the shift in spending will result in a higher cost to California households of $3,857 per year. This is shown below:

Number of housing units in California in 2008	**13,530,719**

Consumer Expenditure Category	**2008**	**Increase**	**Total**
Housing costs	$13,761	$2,048	$15,809
Transportation (Gas and maintenance only)	$3,448	$756	$4,204
Natural Gas	$452	$35	$487
Electricity	$1,113	$124	$1,236
Food (at home and away)	$7,645	$895	$8,539
Total of above	$26,418	**$3,857**	$30,276
All Other Consumer Expenditures	$34,975		$33,179
Total	**$61,393**		**$63,455**

Percent increase in total cost to housing units	**6.47%**
Increased total cost to housing units	**$52,194,231,336**
% decrease in All Other costs to maintain current total costs	**11.63%**

With 13,530,719 household units in California in 2008,[5] the total cost of just these five factors is nearly $52.2 billion. This means that Californians are either going to incur higher costs of nearly 6.5% or reduce their spending in "other areas" by more than 11.6%.

Accordingly, the hoped-for savings that might accrue are too speculative to include as off-sets to the costs. Therefore, the cost of $52.2 billion was used as the expected cost of ARB in this scenario.

Scenario Three: Expected Economic Impact to Small Businesses

Small Businesses are the lifeblood of the economy in California. There are approximately 718,220 small businesses that comprise 99.2% of all employer firms, provide 52.1% of the private sector employment, account for over 90% of new job creation, and contribute approximately 75% of the gross state product.[6]

According to the data from Bureau of Economic Analysis, the receipts from goods and services in California in 2002 (the latest data available) totaled $2.695 trillion. The share of small business receipts of this was $1.145 trillion. The GSP in California grew

[5] California Department of Finance, Table 2: E-5 City/County Population and Housing Estimates, 1/1/2009.
[6] California Small Business Profile, Small Business Association Office of Advocacy.

37.76% from 2002 to 2009. Assuming that small business receipts grew at this same rate (in reality they likely grew faster since the marginal contribution by small businesses to the GSP is higher than those of large businesses), the receipts for small businesses in 2009 is estimated at $1.578 trillion.

Most small businesses are sole proprietorships and financial data from research companies including BizStats show that on average small businesses earn a 10% net profit margin, with the balance 90% being absorbed by expenses and cost structure. From earlier discussion, there are five major areas of cost increases due to the implementation of AB 32 – transportation, housing, food, fuels, and utilities. While the cost increases for each of the five areas is likely to vary, and given estimates provided by several other research studies, it is reasonable to assume that small businesses will likely see at least an average 10% increase in its cost structure that has an exposure to these five costs.

A careful evaluation of the income statements of various industries using financial data from research companies such as American Fact Finder shows that the cost structure for all industries has an exposure to the five areas that ranges from 10% of their cost structure to 80% of their cost structure. Therefore, it is reasonable to assume that the average cost structure exposure for small businesses to the five areas is approximately 45%. A 45% exposure to increased transportations costs, housing costs, fuel costs, food costs, and utility costs that on average increase 10% due to the implementation of AB 32 results in an actual increase of costs to small businesses by 4.5% of its total costs, or $63.895 billion in increased costs on sales of $1.578 trillion.

Therefore, the cost of $63.895 billion was used as the expected cost of ARB to small businesses in this scenario.

FINDINGS

The analyses of the impact of these costs to California businesses and/or consumers were made using the three scenarios identified above.

The study separates the impact into the four categories of output, employment, labor income, and indirect business taxes. It further separates the impact in each category into the major industrial sectors such as manufacturing, wholesaling, retailing, real estate, professional services, administrative, education, health, arts/entertainment/recreation, accommodations/food services, other, farming, federal, and state/local.

- The direct AB 32 cost of $24.878 billion results in a total loss of output of $71.464 billion annually for the State of California (after including indirect and induced costs). The direct cost of $52.194 billion cost to consumers results in total lost output of $149.2 billion annually. The direct cost of $63.895 million to small businesses results in a total loss of output of $182.649 billion annually. The distribution of the output loss is the highest for the professional services sector, manufacturing, arts, entertainment, and recreation sectors.

- In terms of employment, this output loss is equivalent to the loss of roughly half a million jobs for the state due to minimum ARB cost, 900,000 jobs loss due to costs to consumers, and 1.1 million jobs loss due to costs to small businesses. A loss of 1.1 million jobs represents over 3% of the total population of California.

- In terms of labor income, the total loss to the state from the minimum ARB cost is $30 billion, from costs to consumers is $63 billion, and from costs to small businesses is $77 billion.

- Finally, the indirect business taxes that would have been generated due to the output lost arising from the ARB cost is $2.3 billion, from the costs o consumers is $4.7 billion, and from costs to small businesses is $5.8 billion.

- The total AB 32 cost of $182.649 billion in lost output is one and a half times the total budget for the state of California. Further, given the total gross state output of $1.8 trillion for California in 2008, the total lost output from AB 32 costs to small businesses is almost 10%.

- Most importantly, it helps to understand what these costs mean to the small business in California. The total cost of AB 32 is $49,691 per small business in California, indirect business taxes not generated or lost were $1,571 per small business, labor income lost was $20,892 per small business, and finally roughly one third of a job (0.30) lost per small business.

- The increased costs to consumers due to AB 32 means either that they must spend more if they have the funds available or reduce their expenses in other areas. When considering where consumers can make more discretionary reductions in spending, they must reduce expenses by nearly 26.2% across the discretionary categories. This is shown below:

Discretionary Expenditure Category	2008	Reduced
Household operations	$1,196	$883
Housekeeping supplies	$738	$545
Household furnishings and equipment	$2,418	$1,785
Apparel and services	$2,271	$1,676
Health care	$3,047	$2,249
Entertainment	$3,172	$2,342
Personal care products and services	$727	$537
Reading	$154	$114
Education	$1,012	$747
	$14,735	$10,877
Reduction per Expense Category	26.18%	
Increased cost to absorb due to AB 32	$3,857	

- To put into perspective the possible consequences of lost indirect tax dollars, how the lost General Fund revenues could be allocated among various state agencies was computed. Presented in Table 4 are only illustrations of the magnitude of the potential losses. With the minimum impact, these sample agencies would each have to reduce their General Fund budgets by nearly 31.7% to offset the lost tax dollars. If the impact on consumers resulted in lost business taxes, each of these agencies would have to reduce their General Fund budgets by more than 66.1% to offset the lost tax dollars. And, if the impact on small businesses resulted in lost business taxes, each of these agencies would have to reduce their General Fund budgets by nearly 81.0% to offset the lost tax dollars.

CONCLUSIONS

The study analyzes the potential economic impacts of AB 32 on the state of California, its consumers, and the small businesses. Using three different approaches to measuring the economic costs, the study finds that the potential loss of output, jobs, indirect business taxes and labor income is substantial and significant.

On average, the annual costs resulting from the implementation of AB 32 to small businesses are likely to result in loss of more than $182.6 billion in gross state output, the equivalent of more than 1.1 million jobs, nearly $76.8 billion in labor income, and nearly $5.8 billion in indirect business taxes. These are shown below:

Impact	Minimum Impact	Impact on Consumers	Impact on Small Business
Total Output	$71,464,295,356	$149,200,956,684	$182,648,683,516
Total Employment	431,481	900,831	1,102,782
Total Labor Income	$30,046,794,181	$62,730,771,925	$76,793,696,762
Total Indirect Business Taxes	$2,259,805,798	$4,717,953,057	$5,775,619,069

The total AB 32 cost of $182.649 billion in lost output is one and a half times the total budget for the state of California. Given that the total gross state output of $1.8 trillion for California in 2008, the total lost output from AB 32 costs to small businesses is almost 10%. Accordingly, the total cost of AB 32 is $49,691 per small business in California.

These estimated losses represent average losses, with some industries likely to see losses smaller than this and others experiencing much higher levels of losses. Given the uncertainty surrounding the several variables that impact the implementation of AB 32, the upper limit to the losses is unknown. Given conservative estimates including those provided by ARB, the losses resulting from the $24.878 billion in ARB specified costs appear to be the minimum Californians are likely to experience.

It is important to recognize that this analysis focuses on the costs of AB 32 and not whatever savings there may be. The reasons why savings are not used as offsets to costs at this time are:

- There appears to be general agreement that the savings, if any, are unknown. This was recognized in ARB's Scoping Plan, indicated by the LAO's comments, cited by the ARB's peer reviewers, and others.

- Some of ARB's expected savings is derived from yet-to-be developed technologies. Whether these will provide the results anticipated by ARB, and whether they will be developed within California are purely speculative.

- As the LAO indicated, the ARB relies heavily on the Pavley regulations, which account for 70% of the benefits to be generated. Accordingly, even relatively small variations downward in this benefit will significantly alter the net effect. If the benefits were more broadly distributed among factors, small changes in some could more readily be offset by others.

- Some of the savings that are expected to accrue (e.g., solar water heating), require significant investments on the part of businesses and consumers. At this time, there is no indication that such costs could be absorbed by those entities so that the savings would be generated. Additionally, the payback period for the savings is highly speculative.

- This study did not consider all of the costs associated with AB 32., such as the costs or disruptions to prices of crops arising due to changes in land use, costs of reporting, monitoring, and enforcing compliance, future availability of alternative fuels or any major fluctuations or disruptions in the demand supply equation and resulting prices, availability of vehicles utilizing alternative fuels, and costs associated with technology advancements to make the vehicles commercially affordable and reasonably priced, cost of financing of the new production facilities, or of the required investments for both production and distribution, volatility in forecasts of prices of crude, gasoline, and diesel, and research and development costs for lower carbon intensity alternative transportation fuels. Some or all of these additional costs could well offset any savings that might be generated in the future.

- If there are savings, it is unknown whether they will remain inside the state or migrate to other states or countries.

If savings can be conclusively documented, these could serve as offsets to some of the costs included in the study. At this time, however, and given that ARB indicates that the savings are estimates, it was deemed imprudent to speculate on what those would realistically be and how they might impact California's economy, its residents, and small business.

Small businesses drive the economic engine in California. They comprise 99.2% of all employer firms and 99.7% of all firms. They account for over half the employment, over 90% of net new job creation, and 75% of the creation of gross state output. Costs borne by small businesses due to the implementation of AB 32 must be carefully evaluated for a full understanding of their significance and impact on the state and residents.

Currently California is facing one of the highest unemployment rates, worst real estate markets with rising foreclosures, and people looking to move out of the state to find a more affordable living. Businesses, similarly are faced with some of the highest taxes, utility costs, and unfriendly regulatory environment that will likely result in more leakages of businesses elsewhere.

Each of the 50 states in the United States superimposes an array of regulations over and above those that exist at the federal level. An adverse impact on small business is bound to adversely impact the production of goods and services, the risk tolerance of the American enterprise, the productivity of labor, the quality of life, and the overall well being of the State and its citizens.

Legislative and regulatory mandates may result in practices, enact policies that raise the costs of operating for small business or provide a deterrent to small business growth, and hence provide disincentives for economic risk taking and entrepreneurship. This appears to be the case here. While the ultimate goals of AB 32 are not in question, the findings of this study suggest that the costs associated with the implementation of this Act will have a significant adverse impact on California's economy, consumers, and small businesses.

COST OF AB 32 ON CALIFORNIA SMALL BUSINESSES STUDY—SUMMARY REPORT OF FINDINGS

SUMMARY REPORT OF FINDINGS

INTRODUCTION AND PURPOSE OF THIS STUDY

In March 2009, the California Small Business Roundtable (CSBR) commissioned Varshney & Associates to conduct an independent study to examine the possible impact of the Global Warming Solutions Act of 2006 (AB 32, Act) on the California economy, and specifically the impact it will have on small businesses in California (state).

Purpose of this Study

The objective of this research is to describe the impact and cost of AB 32 on California small businesses. Previous studies document the cost of federal regulations on small businesses. The purpose of this study is to identify and establish the various impacts and cost of the AB 32 burden on small business in California and to assess the extent to which this disadvantages small business. This cost is in addition to the cost of federal regulation or state regulation that is widely documented by previously published studies.

Issues addressed in this study include:

- What is the impact of the additional costs associated with implementing AB 32 on the state's economy and on consumers?
- What is the impact of the additional costs associated with implementing AB 32 on small businesses in California?
- How does the cost of AB 32 impact selected industries and economic sectors of California's economy?

In addition to identifying the aggregate direct costs of regulation AB 32 to small business, this study measures the second order costs of this regulation as those resulting from indirect and induced costs and which impact the state's GSP. An example of second order costs is how the cost of environmental regulation will likely be reflected in higher utility bills paid by the consumer. The increased utility costs will have a ripple effect throughout the entire economy, raising costs and impacting productivity and income in all sectors in the state.

As presented below, there can be little question that small business is important to California's economic health. And, there can be little question that legislation impacts all businesses and especially small businesses. Furthermore, AB 32 clearly is an important issue to California and the small business community. Policy recommendations from a Small Business & Entrepreneurship Conference held by the state cited this Act second in its list of recommendations, and requested that the California Air Resources Board (ARB, CARB) "…perform a comprehensive assessment of the interim costs for AB 32 implementation that affects small businesses and identify financing programs that could help alleviate those costs."[7]

Significance of Small Businesses to California's Economy

The significance of this study derives in part from the fact that over 90% of the firms in the United States employ fewer than 20 employees, and large firms (i.e., 500 or more employees) constitute only 0.3% of all firms. In California, according to the California Assembly Committee on Jobs, Economic Development and the Economy (JEDE) "Small businesses are an integral part of the California economy, comprising more than 99 percent of all businesses in the state. Small Businesses in California account for 90% of the net new job creation and over 75% of the net new gross state product. More than 50 percent of all employees in California work for small businesses."[8] Some facts on small business reported by JEDE include:[9]

- An estimated 3.6 million small businesses in California in 2006, with 2.3 million being self-employed firms.

- Nearly 2.5 million people employed by the 630,000 businesses in California with less than 20 employees in 2005.

- Approximately 115,000 new small businesses formed in 2006, compared to 149,000 that closed their doors. Approximately 50 percent of all small businesses fail within seven years of opening.

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[7] "Policy Recommendations of the Small Business & Entrepreneurship Conference Participants, Governor's Small Business Advocate Receives Policy Recommendations from Conference on Small Business & Entrepreneurship Participants, Office of the Governor, Press Release 11/21/2008 GAAS: 796:08.
[8] "An Overview of Small Business issues, Facts, Legislative Actions and Programs in California," California Assembly Committee on Jobs, Economic Development and the Economy.
[9] Ibid.

According to the Governor's Small Business Advocate, "…small businesses are the driving force in the California economy.[10] The Small Business Administration's (SBA's) Office of Advocacy concurs. The SBA received the results of a study it commissioned, showing that the success rate of small businesses has a direct impact on states' economic expansion. In the study, based on 14 years of data, researchers showed that "small firm (...) births have a larger impact than any other factor on Gross State Product (GSP). Economic growth will be faster when the net small firm establishment birth rate is positive."[11] In fact, one study commissioned by the SBA found that increasing small business births by 5% would result in a 0.465% growth in a state's GSP.

Accordingly, small business drives the economic engine and the GSP. An adverse impact on small business is bound to adversely impact the production of goods and services, the risk tolerance of American enterprise, the productivity of labor, the quality of life, and the overall well being of the state and its citizens.

Regulatory Environments and Small Business

Unfortunately, legislative and regulatory mandates can result in practices and policies that raise the costs of operations for small business or provide a deterrent to small business growth. Hence, they may provide disincentives for economic risk taking and entrepreneurship.

Substantial research exists at both the federal and state levels that attempts to understand, measure, and describe the impact that regulation may have on small business and the resulting loss to the economy. Hazilla and Kopp (1990) were early researchers in this field to provide estimates of the indirect effects of environmental regulations as well as the dynamic consequences. Their evidence suggests that these costs are substantial.[12]

Crain (2005) measured the impact of federal regulatory costs on small business by allocating the total impact into those due to economic regulation, workplace regulation, environmental regulation, and finally tax compliance.[13] He found that the burden of federal regulation falls disproportionately on smaller firms relative to larger firms. His study showed that the cost of federal regulation to small business totaled $1.1 trillion in 2004 or 11% of national income. Furthermore, the average cost was $7,647 per employee in firms smaller than 20 employees versus $5,282 per employee for large firms that have more than 500 employees.

[10] "Governor's Small Business Advocate Receives Policy Recommendations from Conference on Small Business & Entrepreneurship Participants," Office of the Governor, Press Release 11/21/2008 GAAS: 796:08.
[11] Dunai, Martin, "California Economic Growth Slips in Rank," Oakland Tribune, February 7, 2007.
[12] Hazilla, Michael and Raymond Kopp, "The Social Cost of Environmental Quality Regulations: A General Equilibrium Analysis," *Journal of Political Economy*, Vol. 98 (4), 1990.
[13] Crain, Mark, The Impact of Regulatory Costs on Small Firms, Small Business Research Summary, 2005.

Keating (2007) created a small business survival index by ranking the policy environment for entrepreneurship across the United States from the friendliest to the least friendly states.[14] According to Keating, the biggest impediments to investment and entrepreneurship are bad public policy, poor public policy environment, and government imposed costs directly and indirectly affecting small business and entrepreneurs. He constructed the small business survival index using 31 different government imposed and related costs that affect small business. These costs include taxes, healthcare regulation, electricity costs, worker compensation costs, total crime rate, right to work costs, number of government employees, tax limitation states, state minimum wage, state legal liability costs, regulatory flexibility, trend in state and local government spending, per capital state and local government spending, protecting private property, and highway cost efficiency.

Based on this study, California ranked 49th among all states ranked from the friendliest to the least friendly for entrepreneurship in the Small Business Survival Index for 2007—just ahead of New Jersey. However, it did improve in rank to 45th for electric utility costs, but 50th (i.e., last) for gas taxes and 44th for highway cost effectiveness.

Huang, McCormick, and McQuillan (2004) measured economic freedom across the United States.[15] Economic freedom was defined to be the right of individuals to pursue their interests through voluntary exchange of private property under a rule of law. They argued that this freedom forms the foundation of market economies. Subject to a minimal level of government to provide safety and a stable legal foundation, legislative or judicial acts that inhibit this right reduce economic freedom. They gathered data on 143 variables per state from 1995 to 2003 that include tax rates, state spending, occupational licensing, environmental regulations, income redistribution, right-to-work and prevailing-wage laws, tort reform, and the number of government agencies, among others. From these they derived five data sets with calculated sector scores for each state by putting each variable into one of five sectors: fiscal (51 variables), regulatory (53), welfare spending (10), government size (7), and judicial (22). Each state's sector scores were calculated by ranking each variable within a sector from one (most free) to 50 (least free). California was ranked 49th, just being edged out by New York for the bottom spot.

Byars, McCormick, and Yandle (1999) perform a similar analysis and their study ranked California 44th out of 50 states.[16] This study demonstrated how a lack of economic freedom especially due to government interference and bad legislation can adversely impact the per capita income of the residents in that state.

[14] Keating, Raymond J., Small Business Survival Index 2007: Ranking the Policy Environment for Entrepreneurship Across the Nation, Small Business Entrepreneurship Council, November 2007.
[15] Huang, Ying, Robert E. McCormick, and Lawrence McQuillen, *U.S. Economic Freedom Index: 2004 Report*, Pacific Research Institute, 2004. However, no estimates of the costs of state regulations are available.
[16] Byars, John D., Robert E. McCormick, and T. Bruce Yandle, *Economic Freedom in America's 50 States: A 1999 Analysis*, State Policy Network, 1999.

The Consultants

Varshney & Associates is a Sacramento-based registered and certified small, minority, and woman owned business providing business and healthcare consulting services. The project team for this study consisted of Dr. Sanjay B. Varshney and Dr. Dennis H. Tootelian. Dr. Varshney is Dean of the College of Business Administration and a Professor of Finance at California State University, Sacramento. Dr. Tootelian is the Director of the Center for Small Business and a Professor of Marketing at California State University, Sacramento. The project team has a strong background in economic and financial analyses, marketing research, and most importantly, small business. Dr. Varshney and Dr. Tootelian have conducted economic impact studies for a variety of public and private organizations. Brief descriptions of Dr. Varshney and Dr. Tootelian are presented in Appendix A.

BACKGROUND ON AB 32

AB 32 is California's landmark global warming legislation. It is intended to reduce California greenhouse gas (GHG) emissions to 1990 levels by 2020 and to 80% below 1990 levels by 2050. Signed into law by the Governor of California on September 27, 2006, the bill establishes a timetable to bring California into near compliance with the provisions of the Kyoto Protocol. The ARB was designated as the lead agency for implementing AB 32.

As defined in the Act, "greenhouse gases" include all of the following gases: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). These are the same gases listed as GHGs in the Kyoto Protocol.

AB 32

The law requires that by 2020 the state's GHG emissions be reduced to 1990 levels, a roughly 25% reduction under business as usual (BAU) estimates.

The Act calls for regulations to do the following:

1. Require the monitoring and annual reporting of GHG emissions from GHG emission sources.

2. Account for GHG emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state.

3. Where appropriate and to the maximum extent feasible, incorporate the standards and protocols developed by the California Climate Action Registry.

4. Ensure rigorous and consistent accounting of emissions, and provide reporting tools and formats to ensure collection of necessary data.

5. Ensure that GHG emission sources maintain comprehensive records of all reported GHG emissions.

Recognizing that there are potentially significant costs associated with implementation of AB 32, and possible impacts on small businesses, the Act required that there be:

- An evaluation of the total potential costs and total potential economic and non-economic benefits of the plan for reducing GHG to California's economy, environment, and public health.

- Account taken of the potential adverse effects on small businesses.

- Regulations that are equitable and seek to minimize costs and maximize total benefits to California.

- Safeguards such that that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

- Consideration given to the cost-effectiveness of the regulations.

- Steps taken to minimize the administrative burden of implementing and complying with the regulations.

The Act also required the ARB to prepare a "S***coping Plan***" to achieve the maximum technologically feasible and cost-effective reductions in GHG emissions from sources or categories of sources of GHG by 2020. The Scoping Plan, approved in December 2008, contained a set of actions designed to carry out the objectives of AB 32.

Elements of the Scoping Plan

The Scoping Plan included goals, recommendations, and the expected economic impact of implementing AB 32. These are highlighted below.

Scoping Plan Reduction Goals

The reduction goals of AB 32 are:

- Greenhouse gas emissions are to be reduced to 1990 levels by 2020 or about 15% from today's levels.

- Meeting this goal means reducing annual emissions from 14 tons of carbon dioxide to 10 tons per person.

- The overall goal is to be able to enjoy clean air, water, and an environment that will benefit the health of Californians.

Scoping Plan Recommendations

Key elements of California's recommendations for reducing greenhouse gas emissions include:

- Strengthening the building and appliance standards while expanding the existing energy efficiency programs.

- Achieving a statewide renewable energy mix of 33%.

- Developing a California cap-and-trade program that links with other Western Climate Initiative partner programs to create a regional market system.

- Creating targets for reducing GHG emissions related to transportation and pursuing policies and incentives to achieve those targets.

- Adopting and implementing measures pursuant to existing state laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard.

- Establishing fees that are targeted to certain things in order to minimize the use. This includes water use, high global warming potential gases, and a fee to fund the administrative costs of the state's long-term commitment to AB 32 implementation.

Changes to specific measures and programs include the following:

- Regional Targets: ARB increased the anticipated reduction of greenhouse gas emissions for Regional Transportation-Related Targets from two to 5 million metric tons of carbon dioxide equivalent.

- Local Government Targets: ARB added a section describing the role that local governments will play in the successful implementation of AB 32.

- Additional Industrial Source Measures: Four additional measures were included to address emissions from industrial sources. It is anticipated that these proposed measures will provide 1.5 MMTCO2E of greenhouse gas reductions.

- Recycling and Waste Re-Assessment: ARB increased the anticipated reduction of GHG emissions from one to 10 MMTCO2E, incorporating measures to move toward high recycling and zero-waste.

- Green Building Sector: It is expected that green building systems have the potential to reduce approximately 26 MMTCO2E of greenhouse gases.

- High Global Warming Potential (GWP) Mitigation Fee: The fee is anticipated to promote development of alternatives to chemicals with very high GWP, and improve recycling and removal of these substances.

- Modified Vehicle Reductions: Heavy-duty vehicle GHG emission reduction and the tire Inflation measure is expected to achieve 0.9 MMTCO2E.

- Discounting Low Carbon Fuel Standard Reductions: this will overlap with California's clean car law and has the result of discounting expected reduction of GHG emissions by approximately 10%.

Scoping Plan Projected Economic Impact

Contained in the Scoping Plan was an analysis of the expected economic impact of implementing AB 32. To make this evaluation, ARB compared estimated economic activity under a BAU case to the results obtained when actions recommended in the Scoping Plan are implemented. The BAU case was an estimate of what the state's economy will be in the year 2020 assuming that none of the measures recommended in the Scoping Plan are implemented. It noted that a number of the measures will be implemented anyway as the result of existing federal or state policies, but these were not included in the BAU model. Presented below is a table from the Scoping Plan that shows the results of ARB's analysis.

Table G-1: Summary of Economic Impact Modeling of the Scoping Plan Using E-DRAM

Economic Indicator	2007	Business-as-Usual[1]	Recommendation[2]
Real Output ($Billion)	2,535	3,597	3,630
Gross State Product ($Billion)	1,811	2,586	2,593
Personal Income ($Billion)	1,464	2,093	2,109
Income Per Capita ($Thousand)	38.6	47.56	47.76
Employment (Million Jobs)	16.41	18.41	18.53
Emissions ($MMTCO_2E$)	500[3]	596	421
Carbon Prices (Dollars)	–	–	10.00

[1] Business-as-usual is a forecast of the California economy in 2020 without implementation of any of the measures recommended in the Scoping Plan.
[2] Includes all measures in the Recommendation in the Scoping Plan, plus additional emission reduction options expected to be undertaken because they are estimated to have a cost-per-ton lower than the market price, as a proxy for reductions from the cap-and-trade program.
[3] Approximate value. ARB is in currently estimating GHG emissions for 2007.

According to the ARB, the results of its economic analysis indicate that implementation of the Scoping Plan will have an overall positive net economic benefit for the state. Positive impacts are anticipated by the ARB primarily because the investments motivated by several measures result in substantial energy savings that more than pay back the cost of the investments at expected future energy prices.

Some of ARB's key economic impact findings include the following:

- The BAU case is anticipated to have the following impact:
    - Gross State Product Increases by $775 billion between 2007 and 2020
    - Personal income grows by 2.8% per year from $1.5 trillion in 2007 to $2.1 trillion in 2020
    - Employment grows by 0.9% per year from 16.4 million jobs in 2007 to 18.4 million jobs in 2020
- Small Business Impacts:
    - Small businesses will not be affected in general. The only additional costs they will incur will be related to changes in the costs of goods and services they need, and changes in energy expenditures.
    - The Scoping Plan recommendation will likely have a slight but positive impact on small businesses.
    - Since small businesses will be saving more with a decrease in electiricity usage, this will be a benefit. Small businesses typically spend more money on energy as a percentage of revenue compared to larger enterprises.

The overall conclusions were that the emission reduction target can be reached without causing harm to the state, and this can be done by increasing economic output, jobs and income. According to the ARB, due to the increased energy efficiency that is supposed to occur, consumers are expected to be better off because they will be spending less on energy, so no additional costs are expected. Business impacts are positive because the promotion of energy efficiency is likely to reduce energy costs for businesses of all sizes over time. California-based technologies also will be brought to the head of the growing global market in green technology, and this will provide jobs and income to many Californians.

The ARB found the primary impacts on small businesses will come in the form of changes in the costs of goods and services that they procure, and in particular, changes in energy expenditures. Due to the number of measures in the Scoping Plan that will deliver significantly greater energy efficiencies, its analysis projects that implementation will have a positive impact on small business in California even after taking into account the higher per-unit energy prices that are likely to occur between now and 2020. According to the ARB, small businesses also will benefit because of the robust economic growth and the increases in jobs, production, and personal income that are projected between now and 2020 as AB 32 is implemented.

Issues Surrounding AB 32 and Scoping Plan

While there appears to be little disagreement with the ultimate goal of AB 32, considerable concern has been expressed about the costs and economic impact of its implementation. Furthermore, the ARB's Scoping Plan and its estimates of the economic impact on California's economy and small business has met with mixed reaction at best.

Legislative Analyst's Office

The Legislative Analyst's Office (LAO), a nonpartisan office of the California Legislature, made a review and analysis of ARB's Scoping Plan at the request of a member of the California Assembly.[17] Its conclusions were:[18]

- The scoping plan's overall emissions reductions and purported net economic benefit are highly reliant on one measure—the Pavley regulations….accounts for about 18% of the plan's emissions reductions … and roughly 70% ($11 billion) of the plan's net direct economic savings to businesses and consumers.

- The plan's evaluation of the costs and savings of some recommended measures is inconsistent and incomplete. The plan does not reflect the costs and savings of all of the emissions reduction measures that it recommends.

- Macroeconomic modeling results show a slight net economic benefit to the plan, but ARB failed to demonstrate the analytical rigor of its findings. The findings are highly dependent upon key assumptions, and ARB has not performed an analysis to determine how sensitive the macroeconomic findings are to changes in the key assumptions.

- Economic analysis played a limited role in development of scoping plan. Selection of particular measures and the mix of measures appear not to have been directly influenced by cost-effectiveness consideration or macroeconomic analysis. In fact, ARB deemed all measure included in the plan "cost effective" simply because they reduce GHG emissions, whatever the costs.

- The plan fails to lay out an "investment pathway." Such a pathway would describe, year-by-year, the investments required by implementation of the plan and the timing of the economic return on those investments. The modeling approach cannot identify the types of disruptions certain parties could face under the proposal. For example, it is possible some businesses could lose money or go out of business.

[17] The Legislative Analyst's Office has been providing fiscal and policy advice to the Legislature for more than 65 years. It is known for its fiscal and programmatic expertise and nonpartisan analyses of the state budget. The office serves as the "eyes and ears" for the Legislature to ensure that the executive branch is implementing legislative policy in a cost efficient and effective manner

[18] Letter to the Honorable Roger Niello dated November 17, 2008 from Mr. Mac Taylor, Legislative Analyst.

The LAO letter further indicates, "The ARB acknowledges that these estimates of costs and savings associated with this measure are weak at present. The scoping plan is based on the uncertain assumption that fuel producers can produce ethanol and biodiesel at costs similar to the current and projected high price of gasoline and diesel. However, ARB did not provide us a basis to justify this major assumption…As a consequence; the bottom-line calculation of net annualized cost/savings could change substantially, depending on the development of more refined estimates for the fuel standard."[19]

While some of the LAO's concerns were addressed by ARB in subsequent communications, the LAO indicated that its observations and concerns about the AB 32 scoping plan and ARB's economic analysis were generally not altered.[20]

Comments from Other Sources

Similar concerns have been expressed by others. For example:

- Los Angeles County Economic Development Corporation: "The LAEDC is satisfied that the model adopted by CARB is a reasonable one for estimating the economic impact of greenhouse gas legislation. We are concerned, however, that some of the key assumptions are unrealistic, which may be contributing to an overstatement of the potential benefits of implementing AB 32….Our concerns…are focused on an unrealistic depiction of baseline conditions; dynamics of cost-benefit analysis; and distributional issues. We suspect that revising some of the key assumptions will produce a less optimistic outcome than currently forecast."[21]

- Peer reviewers brought in by ARB to assess the Scoping Plan:[22]

    - Matthew E. Kahn, Ph.D.: The Economic Analysis and the five appendices contain too many uncertainties for AB 32 to be as flawless as it is presented. Although AB 32 offers many benefits, it will also impose costs that have not been taken into account.

    - Gary Yohe, Ph.D.: Not all of the new technology will emerge from California. This means that additional costs will be incurred to bring in some of the technology required to reach AB 32 goals. In order to achieve a thorough analysis, both the good and that bad must be displayed. It seems that concluding that this plan will cause no harm is inaccurate.

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[19] Ibid, p. 14.
[20] Letter to the Honorable Roger Niello dated December 12, 2008 from Mr. Mac Taylor, Legislative Analyst.
[21] The AB 32 Challenge: Reducing California's Greenhouse Gas Emissions," Los Angeles County Development Corporation, October 2008, pp. 2-3.
[22] Peer Review of the Economic Supplement to the AB 32 Draft Scoping Plan; Major Peer Review Comments and Air Resources Board Staff Responses; November 2008

- Robert Stavins, Ph.D.: The cost estimates that CARB has produced are significant understatements of the true costs, and are useless for identifying a cost-effective portfolio of policies to achieve the objectives of AB 32. "CARB's baseline for its analysis is systematically biased in ways which lead to potentially sever underestimates of costs. In particular, CARB does not include in the baseline some very important existing policies that would be adopted whether or not AB 32 is implemented."

- AB 32 Implementation Group: The Implementation group is not asking AB 32 to stop or be diminished. It simply wants it done correctly so that everyone can benefit. With the plan that has been created, there are many, including small businesses and low-income households, who would be highly impacted. It wants the major flaws identified by the LAO, peer reviewers, and others addressed. It points out that the AB 32 plan includes programs that are currently helping reduce greenhouse gas emissions and will continue to do so even if the AB 32 plan is not completely implemented quickly.

- The Analysis Group: There is no debate about whether the plan's objective is a good one. It is clear that the reduction of greenhouse gas emissions is something that will benefit not only the state of California but also the entire country. "CARB's analysis cannot be considered a reliable or economically sound assessment of the Scoping Plan's economic impact." AB 32 will result in an increase in energy costs for some businesses. This will cause a reduction in their competitiveness, as they will have to allocate more funds to energy expenditures.[23]

- Steven Moore, Senior economics writer for The Wall Street Journal: Employers are becoming extremely concerned as the implementation of AB 32 comes near because it is obvious that the negative impact has been underestimated while the benefits have been exaggerated. Even though none of the reviewers knew who the other reviewers were, they all came up with almost the same conclusion that the report was severely flawed and systematically underestimated costs. Other states are suggesting that business owners move their businesses out of California before the "cap-and-trade earthquake hits". The overall goal of AB 32 is supported, but the consequences of putting it into action are too risky in the opinion of many.

Sectors Most Impacted

The sectors that will be most significantly impacted by proposed measures are energy, construction, transportation, and industry/consumer.

[23] Judson Jaffe and Jonathan Borcke; Analysis Group. Comments on the Economic Analysis Supplement to the Draft Scoping Plan. October 21, 2008

Energy Sector: Major proposed measures include increasing California's renewable portfolio standard (RPS) from 20% to 33%. The RPS requires that California utilities source 33% of the electricity they deliver from renewable resources such as wind, solar, geothermal and biomass. There is also a measure to encourage the installation of solar electric systems, in line with the Million Solar Roofs program.

Construction Sector: There are measures to increase building and appliance efficiency measures, including a major energy efficiency program for state buildings; encourage combined heat and power systems; implement stringent efficiency standards for new construction, and provide incentives for the installation of solar water heating systems.

Transportation Sector: Major proposed measures include implementing the Pavley standards (AB 1493), which would reduce GHG emissions from passenger vehicles by about 22 percent by 2012 and about 30 percent by 2016; and moving forward with a Low Carbon Fuel Standard, which would reduce the carbon content of California's transportation fuels 10 percent by 2020. There are also several early action measures that target goods movement, including a measure to improve the efficiency of heavy-duty tractors and trailers and a measure to reduce emissions at California ports. The only major public transit measure proposes a high-speed rail system between Northern and Southern California.

Industry and Consumer Sectors: For a broad set of industries including manufacturing, gas and oil refining, and others, the main proposed measure thus far is to conduct energy efficiency and co-benefits audits and require investments in cost-effective efficiency measures determined by the audits. These sectors will also be covered by the proposed cap and trade policy. A key issue that impacts these industries is whether ARB will count the emissions produced by out-of-state companies whose products are consumed in California. If it does not, the result could be a "leakage" of jobs and carbon emissions out of California to states and countries with lower environmental standards. Additionally, all of these costs either will be borne by the companies, or more likely passed on in whole or part to the next levels in the delivery chain—and ultimately to the consumer.

Other Sectors: ARB also proposes measures that target agriculture, forests, high global warming potential greenhouse gases (such as SF6), recycling and waste, and the water sector. ARB also proposes 30% minimum emissions reduction by the state government, and plans to work with local governments on measures under their jurisdiction, including building codes, land use, and transit.

METHODOLOGY

The primary model used for this analysis was IMPLAN. It provides modeling based on data and tools to assess economic impacts at the state, multi-county, and county levels. Widely recognized and used nationally and regionally, IMPLAN has more than 1,500 active users in the United States and internationally. These include clients in federal and state government, universities, and private sector consultants. A brief description of IMPLAN and partial list of its users are included in Appendix A.

IMPLAN was used to compute the overall impact, and a specially designed feeder input model was created to provide input to the IMPLAN model that was used for various scenarios described later in this Report.

The benefit of using input-output models, including IMPLAN, is that they help evaluate the effects of industries on each other based on the supposition that industries use the outputs of other industries as inputs. Some other models measuring economic activity examine only the total output or employment of an industry, and not the dual causality that may run both ways. The use of an input-output model provides a much more comprehensive view of the inter-related economic impacts. It examines economic relationships between businesses and between business and consumers. This impact analysis then measures changes in any one or several economic variables on an entire economy.

Each industry that produces goods and services has an influence on, and in turn is influenced by, the production of goods and services of other industries. These interrelationships are captured through a multiplier effect as the demand and supply trickle over from industry to industry (direct and derived demand) and thus impact total output, compensation, employment, etc. Multipliers may vary from one region to another depending on the strength of these interrelationships. IMPLAN data can be used to compute economic impact at the national, state, regional, and county levels. Of particular interest are industry output, employment, value added as measured by employee compensation, proprietary income, other property type income, and indirect business taxes), and final demand of institutions (i.e., households, federal government, state and local governments, businesses).

The full range of economic impacts includes direct, indirect, and induced costs resulting from the implementation of AB 32.

- ***Direct costs*** consist of economic activity contained exclusively within the designated sector(s). This includes all expenditures made and all people employed.

- ***Indirect costs*** define the creation of additional economic activity that results from linked businesses, suppliers of goods and services, and provision of operating inputs.

- ***Induced costs*** measure the consumption expenditures of direct and indirect sector employees. Examples of induced costs include employees' expenditures on items such as retail purchases, housing, banking, medical services, and insurance.

The total direct, indirect, and induced costs arising due to the multiplier effect are presented in four ways:

- ***Output*** accounts for total revenues lost including all sources of income for a given time period for an industry in dollars. This is the best overall measure of business and economic activity because it is the measure most firms use to determine current activity levels.

- ***Employment*** demonstrates the number of jobs not generated and is calculated in a full-time equivalent employment value on an annual basis.

- ***Indirect Business Taxes*** consist of property taxes, excise taxes, fees, licenses, and sales taxes that would have been paid by businesses but now lost. While all taxes during the normal operation of bussinesses are included, taxes on profits or income are not included.

- ***Labor Income*** includes all forms of employee compensation that would have been paid by employers bbut now lost (e.g., total payroll costs including benefits, wages and salaries of workers, health and life insurance, retirement payments, non-cash compensation), and proprietary income (e.g., self employment income, income received by private business owners including doctors, laywers).

The ***multiplier effect*** for sales and employment reflect the diminished economic activity that comes from sales not generated, and expenses not incurred, by a business. When a business generates sales or ceases to do so, it must use some of that money to purchase other goods and other services and hire people to meet the demand for its products and services. If business activity is reduced, that spending which did occur will be lost.

Purchases not made by the business represent lost sales to other firms who must then also cease purchasing goods and services and reduce the employment of people to meet their new demand or layoff people if demand is diminished. The reduced hiring to meet reduced demand means fewer people will have income, which they will use to purchase goods and services for their households. Alternatively, the reduction in personnel will represent lost income that will not be diffused through the economy.

All of this brings lost sales to firms in the community. The net effect is that sales dollars are recycled in the community through this process of sales requiring additional purchases and employment, which result in sales for other firms who must use that money to make their own purchases and hire people. However, if businesses reduce their spending or cease to exist, their past spending represents losses in economic activity within the geographic area[24]

The IMPLAN model can be used to quantify the multiplier effect that occurs when new output or employment is lost in the geographical area via the designated economic activities. The multiplier effect is generated when new output or employment is lost in one sector, but generates less output or employment in other sectors that supply goods and services (indirect impact) and consumer services to employees (induced impact).

The largest component of final demand is household consumption. It includes all payments made by households to all industries for personal consumption of goods and services. Part of total labor income may not be available for spending since it may be used to pay personal taxes, principal and interest on loans, credit card payments, etc. It is also expected that spending patterns will vary from one income level to another. For example at the lower income levels, higher proportional spending takes place on food, clothing, and shelter. At the higher income levels, disposable income is higher for luxury spending.

To provide data for the IMPLAN analysis, the analysts developed a "feeder" economic model that specifically addresses the variables. This model not only provides the data used in the IMPLAN analysis, but allows for a consideration of the impacts at the consumer level.

[24] For example, assume Company A does not receive a new order for $1,000 worth of its products, and the raw materials going into those products cost it $700. Company A will not have to purchase the $700 in raw materials to make those goods from another company (Company B). That $700 becomes lost business for Company B, and it will have to reduce its purchases by some amount from its supplier (Company C) because it does not have to fill the order from Company A. Then, Company C will not have to purchase materials from its supplier (Company D) because it does not have to fill the order from Company B—and this cycle could continue.

Furthermore, Companies A, B, C, etc. may have to employ fewer people (or reduce the hours of employment) because they do not have orders to fill, and that results in less wages for existing employees. These employees will now have less money to spend for their personal use, and their reductions in purchases create lost orders for a variety of businesses within the area.

FINDINGS OF THE STUDY

The findings of the analyses are presented in four sections. The first focuses on the direct costs that were used as input to IMPLAN. This provides the basis for computing the potential impact to California's economy and consumers, and to small businesses. The second, third, and fourth sections provide the results of the analyses based on impacts expected at the minimum level, impacts expected on consumers, and impacts expected on small businesses. These are based on different scenarios for the dollar costs of implementing AB 32. Since there seems to be considerable uncertainty among all parties involved in the implementation and review of AB 32, it was deemed appropriate to provide three scenarios.

Costs of AB 32 Used in the Computations

As previously indicated, there is some uncertainty as to what the actual costs of AB 32 will be. Even the ARB in its Scoping Plan indicated that it was using "…estimated costs and savings … as model inputs for individual measures.'[25] Furthermore, it indicated that "The level of detail on the costs and savings for the different measures included in the Scoping Plan vary widely. Because some of the measures are in the later stages of regulatory development, their costs and savings estimates were readily available. For other measures, the costs and savings were specifically estimated for the Scoping Plan. Many of these estimates are preliminary, and are likely to change during the regulatory process."[26]

Given the extended period and complexity of this Act, some degree of estimation is to be expected. Accordingly, it was deemed appropriate to use three approaches for estimating the economic impact of AB 32 on California's economy. One focuses on the minimum impact using the costs that were identified by ARB, another based on the anticipated costs to California consumers and/or businesses, and the third based on the anticipated costs to California small businesses.

Scenario One: Minimum Impact

According to the ARB, the annualized cost of implementing AB 32 is $24.878 billion.[27] As previously indicated, various analysts believe that there are considerably more costs associated with AB 32 that either were deliberately not taken into account in the ARB analysis or are "hidden costs" that were not acknowledged by ARB. The economic analysis completed by ARB fails to address several key economic issues and variables or the uncertainty surrounding their costs. Examples include:

[25] ARB, "Climate Change Scoping Plan," December 2008, p. 73.
[26] ARB, "Climate Change Scoping Plan Appendices, Volume II," December 2008, p. G-I-1.
[27] ARB, "Climate Change Scoping Plan Appendices, Volume II," December 2008, p. G-I-8.

- Costs or disruptions to prices of crops arising due to changes in land use.
- Costs of reporting, monitoring, and enforcing compliance.
- Future availability of alternative fuels or any major fluctuations or disruptions in the demand supply equation and resulting prices.
- Availability of vehicles utilizing alternative fuels, and costs associated with technology advancements needed to make the vehicles commercially affordable and reasonably priced.
- The cost of financing of the new production facilities, or of the required investments for both production and distribution.
- Volatility in forecasts of prices of crude, gasoline, and diesel.
- Research and development costs for lower carbon intensity alternative transportation fuels.

Initial estimates suggest that billions of dollars of costs will result from the implementation of AB 32. In addition to the costs suggested by ARB, others include infrastructure and capital investment costs upward of $60 billion, $5 billion for new home construction, $36 billion for more fuel-efficient cars, and billions in higher food costs due to higher transportation costs and change in land use. In summary, the implementation costs of AB 32 could easily exceed $100 billion upfront.

Given the uncertainty of costs and greater uncertainty surrounding the suggested benefits or savings that may never be realized, the $24.878 billion cost was used for computational purposes as the minimum cost scenario. As indicated by the LAO, the scoping plan "includes an inconsistent and incomplete evaluation of the costs and savings associated with its recommendations."[28] Therefore, it is likely that this cost is the minimum that will be incurred by businesses and consumers. As previously indicated, the savings identified by ARB are considered too speculative to consider at this time, in part because the outcomes are uncertain and the savings require major investments by businesses and/or consumers that might not be possible.

Scenario Two: Expected Impact to Consumers

The expected economic costs of implementing AB 32 are based on the costs that are projected to be incurred by California consumers. This is predicated on the assumption that the costs to businesses will be shifted through the delivery chain to their customers. Ultimately, therefore, they will reside with consumers. Even if these costs are not or cannot be passed down the delivery chain, they will be incurred and absorbed by businesses. In essence, they will be costs to customers or lost profits to businesses, which will impede their abilities to survive and grow. Given that businesses may not be able to

[28] Letter to the Honorable Roger Niello dated December 12, 2008 from Mr. Mac Taylor, Legislative Analyst, p. 12.

pass down all the increased costs to final consumers, estimates of costs to consumers are likely conservatively stated.

Initially, Census Bureau statistics for consumer spending were used as the basis of how monies are allocated by households. These 2006 statistics were updated based on the Consumer Price Index (i.e., CPI-U) to arrive at figures for 2008.

According to various sources, the costs of AB 32 to consumers will be at least for electricity, gas and fuel, housing, food and other products.[29] As a result, this analysis assumed that costs to businesses and ultimately to consumers would increase in five areas:

- Housing costs: This includes the increased costs of new housing and possible retrofitting of existing homes in an attempt to adjust to higher costs of utilities (see below). It has been estimated by the AB 32 Implementation Group that AB 32 would add approximately $50,000 to the cost of a new home. Because the median new home price in 2008 was $335,990, this represents an increase of 14.9% in the cost of housing.[30] Applying this percentage to what consumers spend for their dwellings excluding mortgage/rent results in a cost increase of $2,048.

- Transportation costs: Higher costs of fuel are likely to occur because consumers will have to purchase new cars, which provide better gas mileage, have their cars retrofitted to obtain better gas mileage, or simply pay the higher costs of gasoline/diesel. In its Scoping Plan, ARB indicated that the savings in fuel costs for new car buyers is $30 per month.[31] Since the average household has 2.1 vehicles, this cost for those who cannot afford to, or will not, purchase new vehicles is $756.[32] It will, of course, be even higher for those that purchase new cars and the savings over time are still uncertain.

- Natural gas: It is generally agreed that natural gas prices will increase because of AB 32. According to the LAEDC, ARB estimates that the retail price of natural gas will be 7.8% higher.[33]

- Electricity: It is generally agreed that natural gas prices will increase because of AB 32. According to the LAEDC, ARB estimates that the retail price of electricity will be 11.1% higher.[34]

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[29] "AB 32's Economic Analysis: Tens of Billions in Hidden Costs," AB 32 Implementation Group.
[30] CBIA/Hanley Wood Market Intelligence New Home Sales and Pricing Report, 2008.
[31] ARB, "Climate Change Scoping Plan," December 2008, p. ES-10.
[32] Bureau of the Census, Table 665. Average Annual Expenditures of all Consumer Units by Region and Size of Unit: 2006
[33] The AB 32 Challenge: Reducing California's Greenhouse Gas Emissions," Los Angeles County Development Corporation, October 2008, p. 4.
[34] Ibid.

- Food costs: Higher costs of transportation, utilities, etc. undoubtedly will increase the costs of food products, whether it is for in-home use or dining outside the home. Given that the cost of food is highly dependent on transportation, utilities, etc., it was assumed that the rise would be approximately half of the increased costs of gasoline and automobile maintenance (i.e., 11.71% of the current costs).

It is highly likely that other costs will increase as well. However, the analysis was limited to these in order to be somewhat conservative.

Based on these five increases alone, the shift in spending will result in a higher cost to California households of $3,857 per year. This is shown below:

Number of housing units in California in 2008	13,530,719

Consumer Expenditure Category	2008	Increase	Total
Housing costs	$13,761	$2,048	$15,809
Transportation (Gas and maintenance only)	$3,448	$756	$4,204
Natural Gas	$452	$35	$487
Electricity	$1,113	$124	$1,236
Food (at home and away)	$7,645	$895	$8,539
Total of above	$26,418	**$3,857**	$30,276
All Other Consumer Expenditures	$34,975		$33,179
Total	**$61,393**		**$63,455**

Percent increase in total cost to housing units	**6.47%**
Increased total cost to housing units	**$52,194,231,336**
% decrease in All Other costs to maintain current total costs	**11.63%**

With 13,530,719 household units in California in 2008,[35] the total cost of just these five factors is nearly $52.2 billion. This means that Californians are either going to incur higher costs of nearly 6.5% or reduce their spending in "other areas" by more than 11.6%.

It is realized, of course, that ARB expects that the increased costs will provide benefits at least comparable to the costs that are incurred. However, this is predicated on two very significant assumptions. One is that the new technology that ARB expects to materialize will deliver on the promises that ARB is making. Since this is unproven and undocumented, it is not considered viable now. Second, it assumes that businesses and/or consumers have the capacity to invest in the new technology even if it does arrive. Given economic conditions within the state and nationwide, and the difficulties that both businesses and consumers are experiencing, this assumption is far from certain.

[35] California Department of Finance, Table 2: E-5 City/County Population and Housing Estimates, 1/1/2009.

Accordingly, the hoped-for savings that might accrue are too speculative to include as offsets to the costs. Therefore, the cost of $52.2 billion was used as the expected cost of ARB in this scenario.

Scenario Three: Expected Economic Impact to Small Businesses

Small Businesses are the lifeblood of the economy in California. There are approximately 718,220 small businesses that comprise 99.2% of all employer firms, provide 52.1% of the private sector employment, account for over 90% of new job creation, and contribute approximately 75% of the GSP.[36]

According to the data from Bureau of Economic Analysis, the receipts from goods and services in California in 2002 (the latest data available) totaled $2.695 trillion. The share of small business receipts of this was $1.145 trillion. The gross state product in California grew 37.76% from 2002 to 2009. Assuming that small business receipts grew at this same rate, when in reality they likely grew faster since the marginal contribution by small businesses to the GSP is higher than those of large businesses, the receipts for small businesses in 2009 is estimated to be $1.578 trillion.

Most small businesses are sole proprietorships and financial data from research companies including BizStats show that on average small businesses earn a 10% net profit margin, with the balance 90% being absorbed by expenses and cost structure. From earlier discussion, there are five major areas of cots increases due to the implementation of AB 32 – transportation, housing, food, fuels, and utilities. While the cost increases for each of the five areas is likely to vary, and given estimates provided by several other research studies, it is reasonable to assume that small businesses will likely see at least an average 10% increase in its cost structure that has an exposure to these five costs.

A careful evaluation of the income statements of various industries using financial data from research companies such as American Fact Finder shows that the cost structure for all industries has an exposure to the five areas that ranges from 10% of their cost structure to 80% of their cost structure. Therefore, it is reasonable to assume that the average cost structure exposure for small businesses to the five areas is approximately 45%. A 45% exposure to increased transportations costs, housing costs, fuel costs, food costs, and utility costs that on average increase 10% due to the implementation of AB 32 results in an actual increase of costs to small businesses by 4.5% of its total costs, or $63.895 billion in increased costs on sales of $1.578 trillion.

Therefore, the cost of $63.895 billion was used as the expected cost of ARB to small businesses in this scenario.

[36] California Small Business Profile, Small Business Association Office of Advocacy.

Findings from IMPLAN Analyses

The analyses of the impact of these costs to California businesses and/or consumers were made using the three scenarios identified above. The findings of the IMPLAN analyses are presented in Tables 1, 2, and 3.

IMPLAN Results

The study separates the impact into the four categories of output, employment, labor income, and indirect business taxes. It further separates the impact in each category into the major industrial sectors such as manufacturing, wholesaling, retailing, real estate, professional services, administrative, education, health, arts/entertainment/recreation, accommodations/food services, other, farming, federal, and state/local.

A summary of the findings from IMPLAN are shown below.

OUTPUT	Minimum Impact	Impact on Consumers	Impact on Small Business
Manufacturing	$5,334,638,471	$11,137,494,041	$13,634,286,623
Wholesaling	$2,134,095,407	$4,455,498,725	$5,454,328,062
Retailing	$3,790,316,458	$7,913,306,180	$9,687,303,351
Real Estate	$5,336,789,678	$11,141,985,268	$13,639,784,451
Professional Services	$37,627,986,489	$78,558,551,540	$96,169,734,108
Administrative	$960,838,671	$2,006,009,401	$2,455,714,624
Education	$412,296,811	$860,780,630	$1,053,749,581
Health	$2,835,699,049	$5,920,285,247	$7,247,488,885
Arts, entertainment, recreation	$1,677,393,481	$3,502,010,529	$4,287,087,676
Accommodations, food services	$1,645,461,653	$3,435,344,317	$4,205,476,229
Other	$5,298,198,984	$11,061,416,988	$13,541,154,399
Farming	$194,802,922	$406,703,551	$497,877,953
Federal	$1,271,387,759	$2,654,364,239	$3,249,417,046
State and local	$2,944,389,523	$6,147,206,028	$7,525,280,528
Foreign trade	$0	$0	$0
Total	$71,464,295,356	$149,200,956,684	$182,648,683,516

EMPLOYMENT	Minimum Impact	Impact on Consumers	Impact on Small Business
Manufacturing	12,203	25,477	31,191
Wholesaling	11,015	22,996	28,151
Retailing	44,707	93,338	114,262
Real Estate	32,205	67,236	82,309
Professional Services	179,953	375,702	459,927
Administrative	11,385	23,769	29,098
Education	6,517	13,607	16,657
Health	24,938	52,065	63,737
Arts, entertainment, recreation	10,350	21,608	26,452
Accommodations, food services	25,706	53,667	65,698
Other	23,105	48,238	59,052
Farming	1,436	2,998	3,671

EMPLOYMENT	Minimum Impact	Impact on Consumers	Impact on Small Business
Federal	10,910	22,778	27,884
State and local	37,051	77,353	94,695
Foreign trade	0	0	0
Total	431,481	900,831	1,102,782

LABOR INCOME	Minimum Impact	Impact on Consumers	Impact on Small Business
Manufacturing	$1,125,004,890	$2,348,750,597	$2,875,291,198
Wholesaling	$823,151,654	$1,718,550,681	$2,103,813,626
Retailing	$1,589,547,021	$3,318,607,387	$4,062,569,546
Real Estate	$1,599,060,250	$3,338,468,841	$4,086,883,308
Professional Services	$17,027,757,859	$35,550,028,089	$43,519,600,793
Administrative	$469,168,650	$979,515,850	$1,199,102,770
Education	$220,728,954	$460,831,139	$564,139,799
Health	$1,608,668,620	$3,358,528,889	$4,111,440,549
Arts, entertainment, recreation	$570,246,414	$1,190,542,932	$1,457,437,654
Accommodations, food services	$593,914,730	$1,239,956,969	$1,517,929,206
Other	$1,029,070,079	$2,148,460,865	$2,630,100,725
Farming	$39,584,019	$82,642,301	$101,168,965
Federal	$951,823,347	$1,987,187,504	$2,432,673,297
State and local	$2,399,067,694	$5,008,699,881	$6,131,545,326
Foreign trade	$0	$0	$0
Total	$30,046,794,181	$62,730,771,925	$76,793,696,762

INDIRECT BUSINESS TAXES	Minimum Impact	Impact on Consumers	Impact on Small Business
Manufacturing	$106,980,551	$223,350,735	$273,421,290
Wholesaling	$302,837,752	$632,255,364	$773,993,696
Retailing	$491,785,332	$1,026,734,301	$1,256,906,579
Real Estate	$288,803,505	$602,955,053	$738,124,928
Professional Services	$511,408,391	$1,067,702,682	$1,307,059,245
Administrative	$12,680,553	$26,474,069	$32,408,999
Education	$3,418,274	$7,136,570	$8,736,438
Health	$22,780,992	$47,561,454	$58,223,734
Arts, entertainment, recreation	$56,596,389	$118,160,202	$144,649,234
Accommodations, food services	$100,477,535	$209,773,911	$256,800,811
Other	$358,168,981	$747,774,185	$915,409,442
Farming	$3,867,543	$8,074,531	$9,884,673
Federal	$0	$0	$0
State and local	$0	$0	$0
Foreign trade	$0	$0	$0
Total	$2,259,805,798	$4,717,953,057	$5,775,619,069

The direct AB 32 cost of $24.878 billion results in a total loss of output of more than $71.464 billion annually for the State of California after including indirect and induced costs. The direct cost of $52.194 billion cost to consumers results in total lost output of more than $149.2 billion annually. The direct cost of $63.895 million to small businesses

results in a total loss of output of nearly $182.649 billion annually. The distribution of the output loss is the highest for the professional services sector, manufacturing, arts, entertainment, and recreation sectors.
In terms of employment, this output loss is equivalent to the loss of nearly 431,500 jobs in the state due to minimum ARB cost, more than 900,800 jobs loss due to costs to consumers, and more than 1.1 million jobs loss due to costs to small businesses. A loss of 1.1 million jobs represents over 3% of the total population of California.

In terms of labor income, the total loss to the state from the minimum ARB cost is more than $30.0 billion, from costs to consumers is more than $63.7 billion, and from costs to small businesses is nearly $76.8 billion.

Finally, the indirect business taxes that would have been generated due to the output lost arising from the ARB cost is nearly $2.3 billion, from the costs o consumers is more than $4.7 billion, and from costs to small businesses is nearly $5.8 billion.

The total AB 32 cost of $182.649 billion in lost output is one and a half times the total budget for the state of California. Further, given the total gross state output of $1.8 trillion for California in 2008, the total lost output from AB 32 costs to small businesses is almost 10%.

Most importantly, it helps to understand what these costs mean to the small business in California. The total cost of AB 32 is $49,691 per small business in California, indirect business taxes not generated or lost were $1,571 per small business, labor income lost was $20,892 per small business, and finally roughly one third of a job (0.30) lost per small business.

Impact on Consumers

The increased costs to consumers due to AB 32 means either that they must spend more if they have the funds available or reduce their expenses in other areas. When considering where consumers can make more discretionary reductions in spending, they must reduce expenses by nearly 26.2% across the discretionary categories. This is shown below:

Discretionary Expenditure Category	2008	Reduced
Household operations	$1,196	$883
Housekeeping supplies	$738	$545
Household furnishings and equipment	$2,418	$1,785
Apparel and services	$2,271	$1,676
Health care	$3,047	$2,249
Entertainment	$3,172	$2,342
Personal care products and services	$727	$537
Reading	$154	$114
Education	$1,012	$747
Total	$14,735	$10,877

Discretionary Expenditure Category	2008	Reduced
Reduction per Expense Category	26.18%	
Increased cost to absorb due to AB 32	$3,857	

Potential Impact on State Agencies

To put into perspective the possible consequences of lost indirect tax dollars, how the lost General Fund revenues could be allocated among various state agencies was computed. Presented in Table 4 are only illustrations of the magnitude of the potential losses. With the minimum impact, these sample agencies would each have to reduce their General Fund budgets by nearly 31.7% to offset the lost tax dollars. If the impact on consumers resulted in lost business taxes, each of these agencies would have to reduce their General Fund budgets by more than 66.1% to offset the lost tax dollars. And, if the impact on small businesses resulted in lost business taxes, each of these agencies would have to reduce their General Fund budgets by nearly 81.0% to offset the lost tax dollars.

CONCLUSIONS

The study analyzes the potential economic impacts of AB 32 on the state of California, its consumers, and the small businesses. Using three different approaches to measuring the economic costs, the study finds that the potential loss of output, jobs, indirect business taxes and labor income is substantial and significant.

On average, the annual costs resulting from the implementation of AB 32 to small businesses are likely to result in loss of more than $182.6 billion in gross state output, the equivalent of more than 1.1 million jobs, nearly $76.8 billion in labor income, and nearly $5.8 billion in indirect business taxes. These are shown below:

Impact	Minimum Impact	Impact on Consumers	Impact on Small Business
Total Output	$71,464,295,356	$149,200,956,684	$182,648,683,516
Total Employment	431,481	900,831	1,102,782
Total Labor Income	$30,046,794,181	$62,730,771,925	$76,793,696,762
Total Indirect Business Taxes	$2,259,805,798	$4,717,953,057	$5,775,619,069

The total AB 32 cost of $182.649 billion in lost output is one and a half times the total budget for the state of California. Given that the total gross state output of $1.8 trillion for California in 2008, the total lost output from AB 32 costs to small businesses is almost 10%. Accordingly, the total cost of AB 32 is $49,691 per small business in California.

These estimated losses represent average losses, with some industries likely to see losses smaller than this and other experiencing much higher levels of losses. Given the uncertainty surrounding the several variables that impact the implementation of AB 32, the upper limit to the losses is unknown. Given conservative estimates including those provided by ARB, the losses resulting from the $24.878 billion in ARB specified costs appear to be the minimum Californians are likely to experience.

It is important to recognize that this analysis focuses on the costs of AB 32 and not whatever savings there may be. The reasons why savings are not used as offsets to costs at this time are:

- There appears to be general agreement that the savings, if any, are unknown. This was recognized in ARB's Scoping Plan, indicated by the LAO's comments, cited by the ARB's peer reviewers, and others.
- Some of ARB's expected savings is derived from yet-to-be developed technologies. Whether these will provide the results anticipated by ARB, and whether they will be developed within California are purely speculative.
- As the LAO indicated, the ARB relies heavily on the Pavley regulations, which account for 70% of the benefits to be generated. Accordingly, even relatively

small variations downward in this benefit will significantly alter the net effect. If the benefits were more broadly distributed among factors, small changes in some could more readily be offset by others.

- Some of the savings that are expected to accrue (e.g., solar water heating), require significant investments on the part of businesses and consumers. At this time, there is no indication that such costs could be absorbed by those entities so that the savings would be generated. Additionally, the payback period for the savings is highly speculative.

- This study did not consider all of the costs associated with AB 32., such as the costs or disruptions to prices of crops arising due to changes in land use, costs of reporting, monitoring, and enforcing compliance, future availability of alternative fuels or any major fluctuations or disruptions in the demand supply equation and resulting prices, availability of vehicles utilizing alternative fuels, and costs associated with technology advancements to make the vehicles commercially affordable and reasonably priced, cost of financing of the new production facilities, or of the required investments for both production and distribution, volatility in forecasts of prices of crude, gasoline, and diesel, and research and development costs for lower carbon intensity alternative transportation fuels. Some or all of these additional costs could well offset any savings that might be generated in the future.

- If there are savings, it is unknown whether they will remain inside the state or migrate to other states or countries.

If savings can be conclusively documented, these could serve as offsets to some of the costs included in the study. At this time, however, and given that ARB indicates that the savings are estimates, it was deemed imprudent to speculate on what those would realistically be and how they might impact California's economy, its residents, and small business.

Small businesses drive the economic engine in California. They comprise 99.2% of all employer firms and 99.7% of all firms. They account for over half the employment, over 90% of net new job creation, and 75% of the creation of gross state output. Costs borne by small businesses due to the implementation of AB 32 must be carefully evaluated for a full understanding of their significance and impact on the state and residents.

Currently California is facing one of the highest unemployment rates, worst real estate markets with rising foreclosures, and people looking to move out of the state to find a more affordable living. Businesses, similarly are faced with some of the highest taxes, utility costs, and unfriendly regulatory environment that will likely result in more leakages of businesses elsewhere.

Each of the 50 states in the United States superimposes an array of regulations over and above those that exist at the federal level. An adverse impact on small business is bound to adversely impact the production of goods and services, the risk tolerance of the American enterprise, the productivity of labor, the quality of life, and the overall well being of the State and its citizens.

Legislative and regulatory mandates may result in practices, enact policies that raise the costs of operating for small business or provide a deterrent to small business growth, and hence provide disincentives for economic risk taking and entrepreneurship. This appears to be the case here. While the ultimate goals of AB 32 are not in question, the findings of this study suggest that the costs associated with the implementation of this Act will have a significant adverse impact on California's economy, consumers, and small businesses.

TABLE ONE: PROJECTED MINIMUM ECONOMIC IMPACT

Output

Industry	Indirect	Induced	Total*
Manufacturing	$892,714,900	$4,441,923,571	$5,334,638,471
Wholesaling	$223,952,220	$1,910,143,187	$2,134,095,407
Retailing	$302,117,966	$3,488,198,492	$3,790,316,458
Real Estate	$844,706,200	$4,492,083,478	$5,336,789,678
Professional Services	$6,032,326,944	$6,595,660,057	$37,627,986,489
Administrative	$431,864,738	$528,973,933	$960,838,671
Education	$2,547,963	$409,748,848	$412,296,811
Health	$309,792	$2,835,389,257	$2,835,699,049
Arts, entertainment, recreation	$1,050,140,832	$627,252,649	$1,677,393,481
Accommodations, food services	$302,248,327	$1,343,213,326	$1,645,461,653
Other	$868,065,241	$4,430,133,743	$5,298,198,984
Farming	$8,167,131	$186,635,791	$194,802,922
Federal	$64,716,619	$1,206,671,140	$1,271,387,759
State and local	$77,805,035	$2,866,584,488	$2,944,389,523
Foreign trade	$0	$0	$0
Total	$11,101,683,908	$35,362,611,960	$71,464,295,356

*Includes $24,878,000,000 in Direct.

Employment

Industry	Indirect	Induced	Total*
Manufacturing	2,646	9,557	12,203
Wholesaling	1,159	9,856	11,015
Retailing	2,867	41,840	44,707
Real Estate	5,611	26,594	32,205
Professional Services	31,519	38,195	179,953
Administrative	4,626	6,759	11,385
Education	41	6,476	6,517
Health	2	24,936	24,938
Arts, entertainment, recreation	4,636	5,714	10,350
Accommodations, food services	4,650	21,056	25,706
Other	6,377	16,728	23,105
Farming	66	1,370	1,436
Federal	580	10,330	10,910
State and local	380	36,671	37,051
Foreign trade	0	0	0
Total	65,160	256,082	431,481

*Includes 110,239 in Direct.

Labor Income

Industry	Indirect	Induced	Total*
Manufacturing	$225,290,682	$899,714,208	$1,125,004,890
Wholesaling	$86,601,619	$736,550,035	$823,151,654
Retailing	$119,972,262	$1,469,574,759	$1,589,547,021
Real Estate	$163,890,456	$1,435,169,794	$1,599,060,250
Professional Services	$2,584,131,656	$2,834,745,051	$17,027,757,859
Administrative	$204,586,409	$264,582,241	$469,168,650
Education	$1,188,554	$219,540,400	$220,728,954
Health	$121,702	$1,608,546,918	$1,608,668,620
Arts, entertainment, recreation	$341,820,659	$228,425,755	$570,246,414
Accommodations, food services	$109,029,867	$484,884,863	$593,914,730
Other	$357,825,767	$671,244,312	$1,029,070,079
Farming	$1,589,313	$37,994,706	$39,584,019
Federal	$49,804,215	$902,019,132	$951,823,347
State and local	$36,457,834	$2,362,609,860	$2,399,067,694
Foreign trade	$0	$0	$0
Total	$4,282,310,995	$14,155,602,034	$30,046,794,181

*Includes $11,608,881,152 in Direct.

Indirect Business Taxes

Industry	Indirect	Induced	Total*
Manufacturing	$34,227,584	$72,752,967	$106,980,551
Wholesaling	$31,934,084	$270,903,668	$302,837,752
Retailing	$16,369,880	$475,415,452	$491,785,332
Real Estate	$92,650,246	$196,153,259	$288,803,505
Professional Services	$117,339,320	$156,645,823	$511,408,391
Administrative	$5,094,005	$7,586,548	$12,680,553
Education	$16,340	$3,401,934	$3,418,274
Health	$2,015	$22,778,977	$22,780,992
Arts, entertainment, recreation	$22,708,934	$33,887,455	$56,596,389
Accommodations, food services	$19,093,841	$81,383,694	$100,477,535
Other	$20,258,899	$337,910,082	$358,168,981
Farming	$183,928	$3,683,615	$3,867,543
Federal	$0	$0	$0
State and local	$0	$0	$0
Foreign trade	$0	$0	$0
Total	$359,879,076	$1,662,503,474	$2,259,805,798

*Includes $237,423,248 in Direct.

TABLE TWO: PROJECTED EXPECTED ECONOMIC IMPACT TO CONSUMERS

Output

Industry	Indirect	Induced	Total*
Manufacturing	$1,863,782,730	$9,273,711,311	$11,137,494,041
Wholesaling	$467,560,537	$3,987,938,188	$4,455,498,725
Retailing	$630,752,612	$7,282,553,568	$7,913,306,180
Real Estate	$1,763,551,576	$9,378,433,692	$11,141,985,268
Professional Services	$12,594,105,096	$13,770,216,172	$78,558,551,540
Administrative	$901,633,877	$1,104,375,524	$2,006,009,401
Education	$5,319,558	$855,461,072	$860,780,630
Health	$646,773	$5,919,638,474	$5,920,285,247
Arts, entertainment, recreation	$2,192,451,714	$1,309,558,815	$3,502,010,529
Accommodations, food services	$631,024,773	$2,804,319,544	$3,435,344,317
Other	$1,812,319,910	$9,249,097,078	$11,061,416,988
Farming	$17,051,085	$389,652,466	$406,703,551
Federal	$135,113,364	$2,519,250,875	$2,654,364,239
State and local	$162,438,972	$5,984,767,056	$6,147,206,028
Foreign trade	$0	$0	$0
Total	$23,177,752,577	$73,828,973,835	$149,200,956,684

*Includes $ $52,194,230,272 in Direct.

Employment

Industry	Indirect	Induced	Total*
Manufacturing	5,525	19,952	25,477
Wholesaling	2,420	20,576	22,996
Retailing	5,986	87,352	93,338
Real Estate	11,714	55,521	67,236
Professional Services	65,805	79,743	375,702
Administrative	9,659	14,110	23,769
Education	86	13,521	13,607
Health	4	52,061	52,065
Arts, entertainment, recreation	9,678	11,930	21,608
Accommodations, food services	9,707	43,960	53,667
Other	13,313	34,925	48,238
Farming	138	2,861	2,998
Federal	1,211	21,567	22,778
State and local	793	76,561	77,353
Foreign trade	0	0	0
Total	136,038	534,639	900,831

*Includes 230,154 in Direct.

Labor Income

Industry	Indirect	Induced	Total*
Manufacturing	$470,354,971	$1,878,395,626	$2,348,750,597
Wholesaling	$180,804,177	$1,537,746,504	$1,718,550,681
Retailing	$250,474,400	$3,068,132,987	$3,318,607,387
Real Estate	$342,165,439	$2,996,303,402	$3,338,468,841
Professional Services	$5,395,069,809	$5,918,293,448	$35,550,028,089
Administrative	$427,129,181	$552,386,669	$979,515,850
Education	$2,481,427	$458,349,712	$460,831,139
Health	$254,085	$3,358,274,804	$3,358,528,889
Arts, entertainment, recreation	$713,642,663	$476,900,269	$1,190,542,932
Accommodations, food services	$227,629,197	$1,012,327,772	$1,239,956,969
Other	$747,057,631	$1,401,403,234	$2,148,460,865
Farming	$3,318,121	$79,324,180	$82,642,301
Federal	$103,979,712	$1,883,207,792	$1,987,187,504
State and local	$76,115,553	$4,932,584,328	$5,008,699,881
Foreign trade	$0	$0	$0
Total	$8,940,476,366	$29,553,630,727	$62,730,771,925

*Includes $24,236,664,832 in Direct.

Indirect Business Taxes

Industry	Indirect	Induced	Total*
Manufacturing	$71,459,325	$151,891,410	$223,350,735
Wholesaling	$66,670,995	$565,584,369	$632,255,364
Retailing	$34,176,537	$992,557,764	$1,026,734,301
Real Estate	$193,432,335	$409,522,718	$602,955,053
Professional Services	$244,977,396	$327,040,326	$1,067,702,682
Administrative	$10,635,106	$15,838,963	$26,474,069
Education	$34,115	$7,102,455	$7,136,570
Health	$4,207	$47,557,247	$47,561,454
Arts, entertainment, recreation	$47,411,013	$70,749,189	$118,160,202
Accommodations, food services	$39,863,536	$169,910,375	$209,773,911
Other	$42,295,905	$705,478,280	$747,774,185
Farming	$383,994	$7,690,537	$8,074,531
Federal	$0	$0	$0
State and local	$0	$0	$0
Foreign trade	$0	$0	$0
Total	$751,344,464	$3,470,923,633	$4,717,953,057

*Includes $495,684,960 in Direct.

TABLE THREE: EXPECTED ECONOMIC IMPACT TO SMALL BUSINESSES

Output

Industry	Indirect	Induced	Total*
Manufacturing	$2,281,603,666	$11,352,682,957	$13,634,286,623
Wholesaling	$572,377,814	$4,881,950,248	$5,454,328,062
Retailing	$772,154,099	$8,915,149,252	$9,687,303,351
Real Estate	$2,158,902,875	$11,480,881,576	$13,639,784,451
Professional Services	$15,417,443,434	$16,857,209,714	$96,169,734,108
Administrative	$1,103,761,304	$1,351,953,320	$2,455,714,624
Education	$6,512,093	$1,047,237,488	$1,053,749,581
Health	$791,765	$7,246,697,120	$7,247,488,885
Arts, entertainment, recreation	$2,683,953,313	$1,603,134,363	$4,287,087,676
Accommodations, food services	$772,487,237	$3,432,988,992	$4,205,476,229
Other	$2,218,603,982	$11,322,550,417	$13,541,154,399
Farming	$20,873,578	$477,004,375	$497,877,953
Federal	$165,402,941	$3,084,014,105	$3,249,417,046
State and local	$198,854,368	$7,326,426,160	$7,525,280,528
Foreign trade	$0	$0	$0
Total	$28,373,722,469	$90,379,880,087	$182,648,683,516

*Includes $63,895,080,960 in Direct.

Employment

Industry	Indirect	Induced	Total*
Manufacturing	6,765	24,426	31,191
Wholesaling	2,963	25,189	28,151
Retailing	7,328	106,934	114,262
Real Estate	14,340	67,968	82,309
Professional Services	80,557	97,620	459,927
Administrative	11,824	17,274	29,098
Education	105	16,553	16,657
Health	5	63,732	63,737
Arts, entertainment, recreation	11,848	14,604	26,452
Accommodations, food services	11,883	53,814	65,698
Other	16,298	42,755	59,052
Farming	169	3,502	3,671
Federal	1,483	26,402	27,884
State and local	970	93,724	94,695
Foreign trade	0	0	0
Total	166,536	654,496	1,102,782

*Includes 281,750 in Direct.

Labor Income

Industry	Indirect	Induced	Total*
Manufacturing	$575,798,682	$2,299,492,516	$2,875,291,198
Wholesaling	$221,336,687	$1,882,476,939	$2,103,813,626
Retailing	$306,625,498	$3,755,944,048	$4,062,569,546
Real Estate	$418,871,734	$3,668,011,574	$4,086,883,308
Professional Services	$6,604,533,175	$7,245,050,594	$43,519,600,793
Administrative	$522,882,606	$676,220,164	$1,199,102,770
Education	$3,037,711	$561,102,088	$564,139,799
Health	$311,045	$4,111,129,504	$4,111,440,549
Arts, entertainment, recreation	$873,626,370	$583,811,284	$1,457,437,654
Accommodations, food services	$278,658,874	$1,239,270,332	$1,517,929,206
Other	$914,532,278	$1,715,568,447	$2,630,100,725
Farming	$4,061,971	$97,106,994	$101,168,965
Federal	$127,289,777	$2,305,383,520	$2,432,673,297
State and local	$93,179,054	$6,038,366,272	$6,131,545,326
Foreign trade	$0	$0	$0
Total	$10,944,745,462	$36,178,934,276	$76,793,696,762

*Includes $29,670,017,024 in Direct.

Indirect Business Taxes

Industry	Indirect	Induced	Total*
Manufacturing	$87,478,998	$185,942,292	$273,421,290
Wholesaling	$81,617,241	$692,376,455	$773,993,696
Retailing	$41,838,197	$1,215,068,382	$1,256,906,579
Real Estate	$236,795,814	$501,329,114	$738,124,928
Professional Services	$299,896,229	$400,355,912	$1,307,059,245
Administrative	$13,019,274	$19,389,725	$32,408,999
Education	$41,762	$8,694,676	$8,736,438
Health	$5,151	$58,218,583	$58,223,734
Arts, entertainment, recreation	$58,039,566	$86,609,668	$144,649,234
Accommodations, food services	$48,800,099	$208,000,712	$256,800,811
Other	$51,777,757	$863,631,685	$915,409,442
Farming	$470,078	$9,414,595	$9,884,673
Federal	$0	$0	$0
State and local	$0	$0	$0
Foreign trade	$0	$0	$0
Total	$919,780,166	$4,249,031,799	$5,775,619,069

*Includes $606,807,104 in Direct.

TABLE FOUR: HOW INCREMENTAL TAX DOLLARS COULD IMPACT STATE AGENCY BUDGETS

	Actual 2007-08 General Fund $s	Reduce Budget to below due to Minimum Impact	Reduce Budget to below due to Impact on Consumers	Reduce Budget to below due to Impact on Small Bus.
Indirect Business Taxes Lost		$2,259,805,798	$4,717,953,057	$5,775,619,069
Arts Council	$1,115,000	$761,776	$377,549	$212,228
California Conservations Corps	$37,383,000	$25,540,319	$12,658,215	$7,115,437
Children's Med. Services & Primary Rural Health	$179,444,000	$122,597,357	$60,761,327	$34,155,164
Coastal Commission	$11,210,000	$7,658,748	$3,795,805	$2,133,698
Department of Aging	$49,071,000	$33,525,640	$16,615,875	$9,340,117
Department of Child Support Services	$400,168,000	$273,397,490	$135,500,428	$76,167,515
Department of Conservation	$11,583,000	$7,913,584	$3,922,106	$2,204,695
Department of Developmental Services	$2,788,254,000	$1,904,954,033	$944,127,489	$530,713,047
Department of Fish & Game	$85,135,000	$58,164,809	$28,827,465	$16,204,498
Department of Food & Agriculture	$98,014,000	$66,963,829	$33,188,408	$18,655,872
Department of Forestry & Fire Protection	$1,025,972,000	$700,951,025	$347,403,202	$195,282,326
Department of General Services	$10,179,000	$6,954,362	$3,446,700	$1,937,459
Depart. of Housing & Community Development	$9,998,000	$6,830,701	$3,385,411	$1,903,008
Department of Parks & Recreation	$141,940,000	$96,974,370	$48,062,141	$27,016,696
Department of Public Health	$349,937,000	$239,079,330	$118,491,766	$66,606,604
Department of Rehabilitation	$56,436,000	$38,557,458	$19,109,729	$10,741,963
Department of Transportation	$1,350,971,000	$922,992,545	$457,450,741	$257,142,260
Department of Veterans Affairs	$178,398,000	$121,882,723	$60,407,142	$33,956,069
Department of Water Resources	$161,324,000	$110,217,650	$54,625,735	$30,706,224
Emergency Medical Services Authority	$11,516,000	$7,867,809	$3,899,420	$2,191,942
Employment Development Department	$27,864,000	$19,036,874	$9,434,997	$5,303,602
Environmental Protection	$83,170,000	$56,822,308	$28,162,098	$15,830,482
Science Center	$17,460,000	$11,928,790	$5,912,111	$3,323,316
State Library	$46,836,000	$31,998,673	$15,859,084	$8,914,710
Total of Above	$7,133,378,000	31.68%	66.14%	80.97%

Source: California Department of Finance: Budget Summary, 2009-10.

APPENDIX A: DESCRIPTION OF PROJECT TEAM

Sanjay B. Varshney

Dr. Sanjay Varshney is the Dean of the College of Business Administration at California State University, Sacramento. He has also worked at the University of San Francisco, and previously served as the Dean of the Business School at State University of New York in Utica. He earned an undergraduate degree in Accounting and Financial Management from Bombay University, a Master's degree in Economics from the University of Cincinnati and a doctorate in Finance from Louisiana State University in Baton Rouge. He also holds the Chartered Financial Analyst (CFA) designation. Additionally, Dr. Varshney is the Principal in Varshney & Associates, a certified woman-owned minority small business.

Sanjay's research interests include market microstructure, new securities issuance and corporate valuation, and his publications have been included in numerous academic and practitioner journals including Journal of Economics and Finance, Journal of Management Research, Studies in Economics and Finance, Journal of Real Estate Finance and Economics, Contemporary Finance Digest, Advances in Financial Economics, and the Journal of Applied Business Research. Additionally, Dr. Varshney's research includes the economic cost of regulations such as compliance with Sarbanes Oxley, Securities and Exchange Commission, and others associated with private and public capital markets for businesses.

Sanjay has also served as a financial consultant for leading Wall Street firms such as UBS Financial Services, Salomon Smith Barney, Fleet Boston, Montgomery Securities, Goldman Sachs, J.B. Oxford, Charles Schwab, and Barclays among others. He is Partner and Principal in an asset management company providing portfolio management for high net worth individuals, trusts, pension programs, and corporations. He is also Partner and Principal of Varshney & Associates that provides management consulting and financial services to a variety of clients including the healthcare industry.

Sanjay has a strong training and background in statistics, econometrics, and research methodology including but not limited to research sample design, time series, and cross-sectional. He has conducted numerous research studies for both private sector and public sector entities. Most recently, he was contracted by SMUD to independently evaluate, verify, and validate the methodology and assumptions used by consultant and staff studies to support the Yolo annexation. Dennis Tootelian and he also completed a detailed economic study measuring the impact of the annexation on the four-county Sacramento region.

Sanjay currently serves on the boards of Wells Fargo Bank, SACTO, SARTA, Sacramento Metro Chamber of Commerce, CFA Society of Sacramento, The Sacramento Entrepreneurship Academy, and Comstock's Business Magazine. He is also a member of the Chartered Financial Analysts Society of Sacramento, the downtown Rotary, and is engaged in a variety of business program activities. Dean Varshney has been featured widely in the media and on television including the Sacramento Bee, Prosper magazine, Comstock Magazine, the Business Journal, Sacramento Magazine, ABC, NBC, CBS, and Fox News.

Dr. Varshney has a very strong background in finance and economics. He brings an expertise in how costs of regulations impact business survival and profitability. He is the Principal of Varshney and Associates.

Dennis H. Tootelian, Ph.D.

Dr. Dennis H. Tootelian is the Director of the Center for Small Business and a Professor of Marketing in the College of Business at California State University, Sacramento. He received his Ph.D. in Marketing from Arizona State University, with minor fields in Accounting and Management. Dr. Tootelian also is the Principal in Tootelian & Associates.

The Center for Small Business provides technical management assistance to small firms and is one of the oldest and largest of its kind in the United States. It routinely serves about one hundred small companies each year. Dr. Tootelian has won numerous awards for his work with small business, including Advocate of the Year by the District Office of the United States Small Business Administration.

Dennis has published approximately one hundred articles dealing with all facets of business, and has co-authored six texts on marketing and small business management. His academic research has appeared as articles in such journals as the Journal of Marketing, Journal of Retailing, Journal of Business Research, Journal of Health Care Marketing, and Journal of Professional Services Marketing. Results of some of his applied research and writing have appeared in The Congressional Record, The Wall Street Journal, Forbes, The Kiplinger Report, USA Today, ABC National News website, and even The National Enquirer.

Dennis has worked in a consulting capacity with businesses that are Fortune 500 companies (e.g., McDonald's Corporation, Merck, Johnson & Johnson, 3M, Target Stores, Nestles U.S.A., McKesson Corporation), professional and trade associations (e.g., California Pharmacists Association, California Dental Association), and federal and state governmental agencies (e.g., Centers for Disease Control, California Environmental Protection Agency, California Department of Parks and Recreation, California Department of Insurance). He also has served on the Board of Directors for a variety of publicly traded companies and not-for-profit organizations.

He also has a strong background in consulting to state government and the private sector. At the state and federal government levels, Dennis has conducted survey research for the California Integrated Waste Management Board, Franchise Tax Board, California Department of Food and Agriculture, California Department of Pesticide Regulation, California Public Employment Retirement System, California Conservation Corps, and the Centers for Disease Control. On the private level, he has conducted marketing research for such Fortune 500 companies as Merck, McDonald's, Nestle USA, and the McKesson Corporation. Accordingly, Dr. Tootelian is an expert in small business matters and marketing research. His experience in working with small businesses is a critical resource for understanding the costs and benefits of regulation on small organizations.

SUPPORTING DOCUMENTS FOR
DIRECT TESTIMONY OF MICHAEL BROWN

Exhibit 17

Expert Report on Issues Affecting Small Businesses

Testimony of Michael Brown

on behalf of

Small Business Utility Advocates
548 Market Street, Suite 11200
San Francisco, CA 94104
Tel: 415-602-6223 Fax: 415-789-4556

California Public Utilities Commission
Application 12-11-009
May 16, 2013

NEWS AND PERSPECTIVES FROM PACIFIC GAS AND ELECTRIC COMPANY
MAY 10, 2013

Posted on June 13, 2012

PG&E Wants Customers to Receive Revenue from Greenhouse Gas Reduction Law

By Lynsey Paulo

Six years after supporting the nation's first mandatory greenhouse gas reduction law, PG&E now encourages California lawmakers to protect consumers.

The California Global Warming Solutions Act of 2006 (AB 32) requires the state to cut greenhouse gas emissions to 1990 levels by 2020.

Under the law's cap-and-trade program, utilities and other covered industries can purchase allowances at auction to help cover carbon dioxide emissions. In order to mitigate AB 32 costs for utility customers, the Air Resources Board has given the utilities allowances that must be sold at auction. The first cap-and-trade auction is scheduled for November and compliance with the emissions cap will begin in 2013.

PG&E, along with California's other investor-owned utilities and some consumer groups, have filed a proposal with the California Public Utilities Commission asking to return 100 percent of the utility allowance revenue back to customers in proportion to the costs they incur.

Under this proposal, customers who would otherwise experience direct increases in their electricity rates on average of 5.3 percent, would have a portion of these costs reduced. Without the revenue return, the impact on higher-use electricity customers would be even greater. The revenue would be returned to customers through rates on their monthly bill.

However, some members of the state legislature want to use the money in other ways. And some believe that could threaten the success of the landmark legislation.

"We have to show that we can reduce greenhouse gas emissions without it having a significant cost impact on our customers," said Steve Malnight, vice president of Customer Energy Solutions for PG&E. "This is the most critical component to ensuring success and creating a model program for others to follow."

Several lawmakers have proposed using the money for energy efficiency programs instead of giving it back to consumers. Most recently, the Assembly Budget Committee Report called for up to 25 percent of investor-owned utility auction revenues to be used for clean energy projects.

"While we think these are good objectives, we already invest significantly for the benefit of our customers," said Malnight. "Our customers help fund energy efficiency programs at about $600 million a year."

PG&E opposes all of these efforts as unfair and inequitable to its customers.

The legislature has to pass a budget by Friday (June 15) or lawmakers risk losing their pay.

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