A. Pacific Gas and Electric Company

1. Summary of Report and Recommendations to CPUC and Legislature to Reduce Utility Costs and Rates

Pursuant to the requirements of Senate Bill (SB) 695, which was codified into Public Utilities Code Section 748, Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide its annual study and report to the California Public Utilities Commission (CPUC or Commission) on measures PG&E recommends be undertaken to limit costs and rate increases.

This report describes:

- PG&E's overall rate policies;
- A discussion of PG&E's management of its costs and rates;
- A discussion of PG&E's recommendations to further manage costs and rates;
- Data and forecasts related to PG&E's gas and electric revenue requirements and load; and
- A schedule of PG&E's filings that may or will affect rates in 2015 and beyond.

PG&E knows how important it is for our customers to keep monthly electricity and gas costs affordable while maintaining safe and reliable service. In addition to mitigating cost pressures, within the framework for the allocation of costs and rate design mandated by the California Legislature (Legislature) and the CPUC, PG&E seeks to equitably allocate costs among its customers based on cost-of-service principles. Crafting equitable allocation rules for revenue requirements among and within customer classes also poses challenges, largely due to rate designs mandated by law and the need to collect revenues to fund programs that benefit a specific set of customers but are paid for by nonparticipating customers.

One of the biggest obstacles to creating fair and equitable rates has been the statutory mandate for tiered residential electric rates that included protected tiers. Today, PG&E's upper-tier residential rates (for usage in Tiers 3 and 4) remain far in excess of cost of service and are among the highest at the large investor-owned utilities in the country.

In 2013, the Governor signed into law Assembly Bill (AB) 327, which removes many (though not all) of the restrictions on the Commission's ability to adjust residential tiered rates and reduce the large gap between the top and bottom tier rates. AB 327 also mandates that, after a reasonable transition period, PG&E's average CARE[1] discount be reduced from its current level of just below 40 percent to between 30 and 35 percent. With the restoration of much of its pre-energy crisis ratemaking authority, the Commission is now able, over a reasonable period, to make residential rates more closely reflect cost of service. In Decision 14-06-029, the CPUC took the first step towards residential rate reform, approving rate levels effective in summer 2014 that began narrowing the gap between top and bottom tier rates, and reduced the CARE discount towards the range mandated by AB 327. PG&E has a proposal pending before the Commission for further rate reform in 2015 and beyond, which includes implementing a monthly fixed charge, reducing the number of tiers to two, further reducing the tier rate differential, and further

[1] CARE or the California Alternate Rates for Energy program offers a rate discount for electric and gas service to residential customers who meet certain income criteria.

reducing the average CARE discount. The CPUC is expected to rule on this proposal in the second quarter of this year, in time for summer rate relief for PG&E's upper-tier users.

Another area of concern regarding impacts on electricity rates is the overall cost-shift associated with customer-owned generation, particularly residential generation that participates in the Net Energy Metering (NEM) program. The NEM tariff allows customers with on-site generation (primarily rooftop solar photovoltaic (PV) equipment) to receive a full retail rate credit (for generation plus transmission and distribution rates plus public purpose program and other non-bypassable charges) for the energy they send out to the grid to offset the cost of their consumption within the month and within an annual true-up period. NEM rates compensate customers who install renewable on-site generation well in excess of the market-based costs of generation otherwise paid by PG&E on behalf of non-participating customers. As a result, NEM customers do not pay their share of the fixed costs associated with accessing the grid. These fixed costs are instead shifted to customers for whom roof-top generation is not feasible, affordable or desired.

While PG&E supported the enactment of the NEM program and subsequent expansion to meet the policy goals of the California Solar Initiative as embodied in SB 1 (Chpt.132, Stats of 2006), the program was established to assist in developing a solar market. That market is now well developed and the continued compensation for customer-owned generation should reflect fair wholesale market prices that do not shift fixed costs to other customers.

Mandated residential rate designs have magnified the impact of the cost-shift associated with customer-owned generation. Until very recently, any increases in rates—including those caused by these cost shifts—were borne by upper tiers. In contrast, three-fourths of NEM customers served by California's three large investor-owned utilities pay effective rates below the average cost to serve them. This inequity is exacerbated by the fact that rooftop solar systems are generally owned by customers with higher than average incomes.

Now that the solar market is developed, the costs of PV installations have dropped significantly, and PV adoption has increased dramatically. As a result, large subsidies provided to NEM customers at the expense of non-participating customers are no longer required to develop the solar industry, and these subsidies must be reformed to *sustainably* accommodate continued growth in such generation for the benefit of all customers, including non-participants.

AB 327 addressed the NEM cost shift in addition to general rate design issues. With respect to NEM, AB 327 charged the CPUC with two tasks. First, the CPUC had to create a transition plan for customers participating in the current NEM program by March 31, 2014. This transition plan, issued in Decision 14-03-041, ensured that existing NEM customers have the opportunity to recover the costs of their investment in renewable generation. Second, the CPUC must complete a redesign of the NEM program and develop a successor to NEM tariffs by December 31, 2015. The successor program must protect the economic interests of non-participating customers while ensuring a sustainable renewable generation market for our customers. PG&E will submit its rate proposal for the successor NEM program later in 2015 in Rulemaking 14-07-002.

In addition to the rate design issues described above, PG&E also looks for ways to manage and reduce its costs – consistent with the provision of safe, reliable and responsive customer service. In recent years, PG&E has had three significant rate cases before the Commission that address these key attributes of service – the 2014 General Rate Case, the Pipeline Safety Enhancement Plan proceeding, and the Gas Transmission and Storage rate case.

PG&E's 2014 General Rate Case (GRC) forecast request, approved as modified by the CPUC in 2014, included not only increased expenditures to improve safety, reliability and customer service, but also reductions to capture efficiencies throughout PG&E's operations. Notably, the forecast included significant operational savings achieved by the implementation of SmartMeter™ technology, which were reflected as reductions in PG&E's forecasted costs. The 2014 GRC forecast also reflected efforts to reduce costs and improve efficiencies in other areas of operations. For example, PG&E's electric distribution operation expects to offset cost pressure from normal inflation through 2015. Finally, while PG&E believes that its plans ensure safe operations for its customers, the public and employees, the CPUC hired independent consultants to assess those plans and make recommendations related to the safety and security of the plans. The consultants' reports reinforced the need for the Company's planned investment to improve the safety of its gas and electrics operations.

Also, beginning in 2011 and continuing in 2014, PG&E embarked on a multi-year program to enhance the safety and reliability of the natural gas transmission pipelines in communities throughout its service area, as approved in CPUC Decision 12-12-030. This program improves the delivery of safe and reliable natural gas to customers. Hydrostatic pressure testing is one of several important measures PG&E is taking to enhance the safety and strength of its natural gas system. Through the end of 2014, per its Pipeline Safety Enhancement Plan program as updated on October 29, 2013, in Application 13-10-017, PG&E has pressure tested 673.5 miles of gas transmission pipeline, replaced 127 miles of pipeline, automated 208 valves, and upgraded 201 miles of pipeline to accommodate advanced in-line inspection tools known as "smart pigs." This program, which is partially funded through shareholder dollars, has increased customer bills by less than a dollar per month.

In its December 2013 Gas Transmission and Storage rate case application PG&E requested CPUC authorization of its 2015 revenue requirement of $1.29 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $555 million over currently authorized amounts. PG&E also requested attrition increases of $61 million in 2016 and $168 million in 2017 for increasing capital expenditures and the associated growth in rate base, as well as increasing costs of labor, materials, and other expenses. PG&E's risk based portfolio of programs is consistent with SB 705 which requires that gas operators go beyond adequate and develop and implement safety plans that are consistent with best practices in the utility industry. If approved, PG&E's 2015 Gas Transmission and Storage rate case will enable PG&E to implement a vintage pipe replacement program, hydrostatic test approximately 170 miles of pipe each year and add an additional 516 miles capable being "made piggable" to accommodate in line inspection tools. A final decision is expected in August 2015.

Aside from these major rate cases, certain components of gas and electric rates are largely beyond the direct control of utilities, and instead result from policy or regulatory mandates (many of which PG&E and the CPUC supported). Among the requirements that are creating further cost pressures on PG&E's electric and gas rates are the Renewables Portfolio Standards (RPS) program and greenhouse gas (GHG) emissions restrictions resulting from AB 32.

These legislative and regulatory mandates and policies seek to achieve worthy overall goals. However, to the extent that they raise electric and gas rates or restrict the ability of utilities to manage or mitigate costs, then the Legislature and Commission should periodically review these mandates and policies to ensure that they appropriately balance the social or customer benefits with the overall cost to customers. To mitigate the impact of AB 32 costs, PG&E, Southern California Edison, and San Diego Gas and Electric Company in the Greenhouse Gas OIR (R.11-03-012) proposed to return the entire amount of allowance auction revenues (less allowable expenses, i.e. outreach and administration costs) directly to utility customers. However, under SB 1018 (Chpt. 39, Stats of 2012) and consequently in CPUC Decision 12-12-033, certain customers are excluded from receiving GHG allowance credits. Consequently, nonresidential and non-"emissions-intensive trade exposed" customers with demands greater than 20 kilowatts will not have their bill increases mitigated. In addition, development of an RPS procurement expenditure limitation is currently being addressed in the Renewables Portfolio Standard OIR (R.11-05-005).

PG&E believes that review of these measures and issues can have a beneficial near-term impact on its total cost of delivering safe and reliable gas and electric services to its customers.

2. Overall Rate Policy

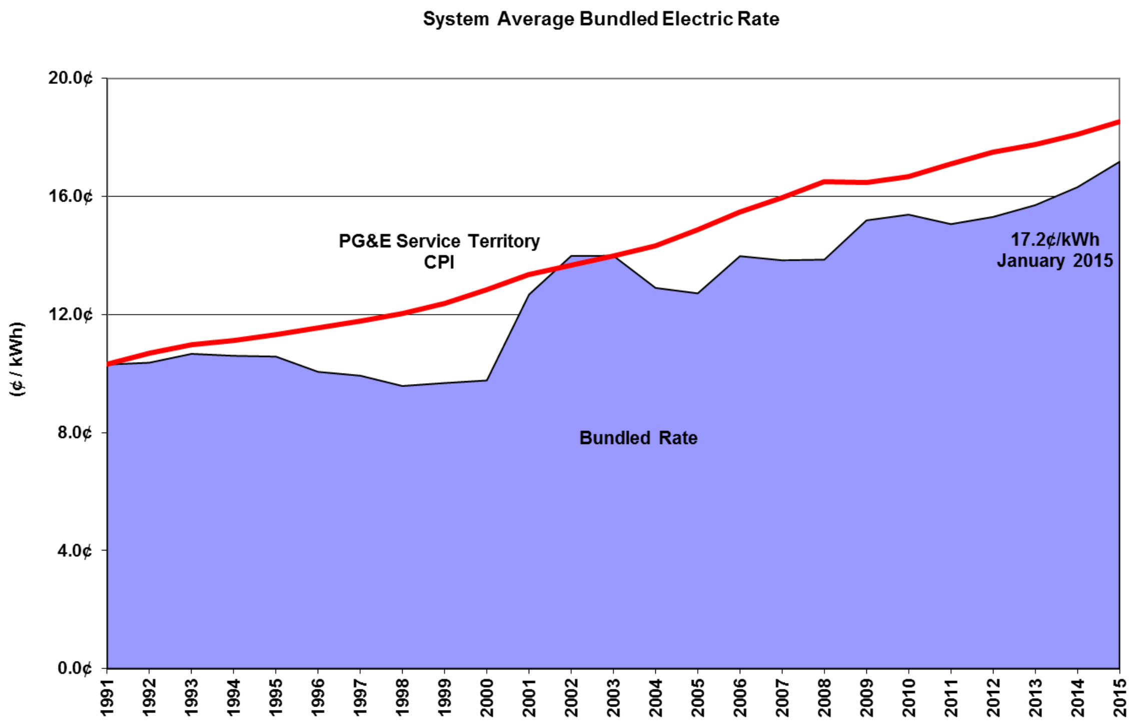
PG&E strives to provide its customers with reasonable rates for gas and electric service. When proposing rates, PG&E considers cost-based pricing, equity within and among customer classes, simple and understandable rates, and public policy objectives.

PG&E understands that its customers value transparency and stability in the rates they pay for energy. Therefore, PG&E limits the number 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 occasionally one more change in the summer or fall). For gas rate changes, as required by prior Commission decisions, PG&E files monthly changes to the gas commodity rate and seeks an annual rate change to reflect gas transportation and Public Purpose Program costs. 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 reliable and cost-effective service to its customers.

PG&E also undertakes efforts to manage the timing of revenue changes and subsequent rate changes to smooth the impact on customers. For example, in 2007 and 2011, PG&E proposed and received approval for a "rate stabilization adjustment" plan that eliminated a looming situation where electric rates would have dropped precipitously in January only to increase later in the year. Another more recent example is how PG&E implemented Decision 14-08-032, which was issued in August 2014 in PG&E's 2014 GRC. PG&E began collecting approximately half of the adopted 2014 GRC electric revenue requirement increase on October 1, 2014. Subsequently, PG&E requested in its 2015 Annual Electric True-Up Advice Letter that it be allowed to recover the remaining half of the adopted 2014 electric revenue requirement increase for a period of up to 24 months. The Commission approved PG&E's request in Resolution E-4693. In contrast, PG&E began collecting the 2014 GRC gas revenue requirement increase on September 1, 2014, and recovered only four months' worth of the 2014 increase in the gas revenue requirement. PG&E requested in its 2015 Annual Gas True-Up Advice Letter to recover the remaining eight months of its 2014 gas revenue requirement in 2015. PG&E employed different approaches for gas and electric rate increases resulting from the 2014 GRC in order to avoid residential customers seeing radical swings in their combined gas and electric bills.

As illustrated in Figure 1 below, PG&E's system average bundled electric rate over the last 24 years has increased at a lower rate than the service territory's consumer price index (CPI) growth. It is also worth noting that rates in the upper tiers for residential service have far outpaced CPI, which is of great concern to PG&E.

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



3. Management Control of Rate Components

PG&E is committed to controlling costs and managing rates while providing safe and reliable gas and electric service to its customers. However, many factors that affect customer rates are outside of PG&E's control. Among these are the market prices of natural gas and electricity, retail sales volumes, uncollectible accounts, weather (including the impacts on hydroelectric operations), interest rates, the cost of implementing state mandates, and permitting process delays. Nonetheless, PG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

4. PG&E's Policies and Recommendations for Limiting Costs and Rate Increases While Meeting the State's Energy and Environment Goals for Reducing Greenhouse Gases

PG&E and the Commission have endorsed rate policies based on cost of service. Such policies encourage efficient decision making by customers. At times, departing from cost-based rates can be appropriate in order to accomplish other public policy objectives. Such objectives may include energy efficiency, benefits to low-income customers, mitigation of rate changes from year to year, promotion of renewable generation, greenhouse gas (GHG) emissions reductions, and encouraging innovation and developing technologies.

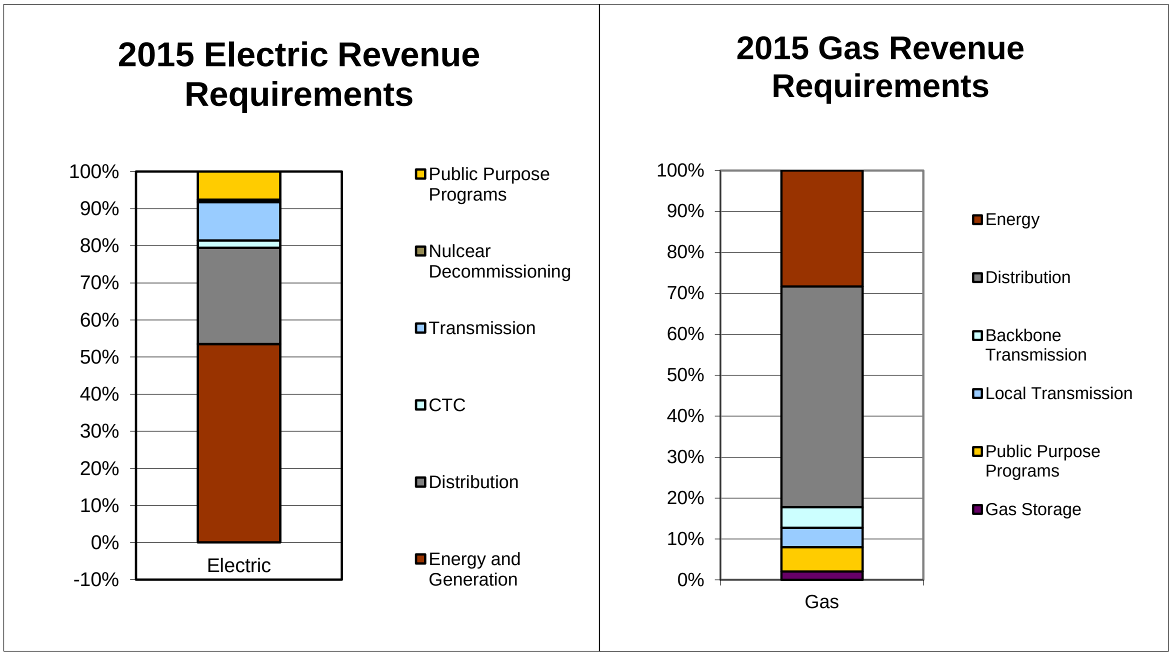
However, each departure from cost-based rates needs to be carefully evaluated to determine whether the rate increases are reasonable in light of the overall benefits to society and the impact on non-benefiting customers. For example, Net Energy Metering encourages customer adoption of solar generation but shifts costs onto other non-participating customers. It may be warranted as a policy when the cost shift is relatively small, but become questionable as the cost shift grows. Similarly, the Legislature determined that the cost to support low-income CARE customers, which in PG&E's case ballooned to more than $750 million a year, was unsustainable. As a result, AB32 mandates that the CARE subsidy be reduced over time to a range of 30 to 35 percent, from a high in PG&E's case of about 49 percent.

PG&E respectfully requests the Commission's support by approving rate proposals in current and future rate proceedings that are designed to reduce the extremely high levels of upper-tier rates and reduce subsidies associated with the Net Energy Metering program. If these proposals are not approved, upper-tier rates are projected to continue growing, potentially resulting in resistance to adopted public policy goals such as the 33 percent Renewable Portfolio Standard, AB 32, and replacement of aging infrastructure.

5. Description of Revenue Requirements

PG&E's electric and gas authorized January 2015 revenue requirement categories are provided in Figure 1 below. A description of each category and the percent contribution to the total revenue requirement is provided separately for electric and gas. The key categories of revenue requirements are based on PG&E's major rate components.

Figure 1: High Level Breakdown of PG&E's 2015 Revenue Requirements



a. Electric revenue requirements are grouped into the following major rate categories: (1) Energy and Generation, (2) Competition Transition Charge (CTC) and New System Generation Charge (NSGC), (3) Distribution, (4) Energy Recovery Bonds (ERB) and Department of Water Resources (DWR) bonds, (5) Transmission, (6) Public Purpose Programs (PPP), and (7) Nuclear Decommissioning. For reference, an excerpt from the Advice 4278-E-B Annual Electric True-Up filing is provided as Table 1 below. Below is a description of each electric revenue requirement category:

1) Energy and Generation contribute approximately 53 percent to the total authorized electric revenue requirement in 2015. The generation rate component recovers the following energy and generation related revenue requirements:
   - Procurement costs that are not determined to be above-market in the Energy Resource Recovery Account Proceeding;
   - Utility Owned Generation; and
   - Department of Water Resources Power Charges and associated franchise fees.

2) The Competition Transition Charge revenue requirement contributes approximately 2 percent to the total authorized revenue requirement in 2015. This represents the above-market cost of procuring energy. This category includes the New System Generation revenue requirement, which recovers program and other contracts for which PG&E is authorized to recover net capacity costs from Direct Access, Community Choice Aggregation, and departing load customers through the NSGC rate.

3) Distribution contributes approximately 26 percent to the total authorized revenue requirement in 2015. The Electric Distribution revenue requirement includes the 2014

General Rate Case, California Solar Initiative, AB32 Revenue Return, and several other programs that are recovered through the distribution rate component.[2]

4) The Energy Recovery Bond and Department of Water Resources bond revenue requirement result in a net reduction of $30 million to PG&E's authorized 2015 revenue requirement.

5) Electric Transmission contributes 10 percent to the total authorized revenue requirement in 2015. Transmission revenue requirements include those related to the following:
   - Transmission Owner;
   - Transmission Access Charges;
   - Transmission Revenues;
   - Reliability Services; and
   - Electric Customer Refund Account.

6) The Electric Public Purpose Programs revenue requirements contribute 8 percent to PG&E's total authorized revenue requirement in 2015. These revenue requirements include the funding of energy efficiency programs and the CARE discount.

7) The Nuclear Decommissioning revenue requirement contributes less than 1 percent to PG&E's total authorized revenue requirement in 2015.

[2] The CARE discount shifts revenue requirements from the distribution rate component to the Public Purpose Program rate component. The revenue requirements shown here do not reflect that shift.

Table 1: Excerpt from Advice 4484-E-A Annual Electric True-Up filing for Electric Rates Effective January 1, 2015

Table 2: Annual Electric True-Up Projected 2015 Revenue Requirements

Line #		Test Year 2015 RRQ A	12/31/14 Forecast BA Amortization B	Total Projected 2015 Revenues C = A + B
1	**CPUC Jurisdictional**			
2	**Distribution**			
3	Distribution Base/DRAM [4]	3,976,628,000	134,901,276	4,111,529,276
4	Pension Contribution (Distribution & Generation) [1]	146,885,000		146,885,000
5	FERABA (Distribution & Generation) [2]		6,224,973	6,224,973
6	Demand Response [5]	56,703,296		56,703,296
7	Statewide ME&O/Demand Response [5]	8,033,616		8,033,616
8	DREBA		(4,622,299)	(4,622,299)
9	Self Generation Incentive Program [5]	29,967,197		29,967,197
10	CPUC Fee	20,841,593		20,841,593
11	California Solar Initiative [5]	95,115,028		95,115,028
12	HSM		20,174,205	20,174,205
13	CEEIA	30,080,714	2,415,470	32,496,184
14	NTBA		(119,280)	(119,280)
15	SGPDPBA (Distribution and Generation) [3]	(6,632,000)		(6,632,000)
16	SGMA (Compressed Air Energy Storage)		4,155,043	4,155,043
17	RCESBA		2,847,523	2,847,523
18	CES21BA-E	0	0	0
19	CDABA		423,488	423,488
20	Hercules Municipal Utility Acquisition (D.14-01-009)	1,097,000		1,097,000
21	Mobile Home Park Balancing Account		224,085	224,085
22	GHG Revenue Balancing Account (GHGRBA)	(303,292,000)	(133,914,000)	(437,206,000)
23	AAASMA to be transferred to DRAM		253,231	253,231
24	**Generation**			
24	Utility Retained Generation Base/UGBA [4]	1,963,820,000	137,390,950	2,101,210,950
25	UGBA - Photovoltaic Program Credit		(41,300,000)	(41,300,000)
26	UGBA - Department of Energy Litigation Proceeds		(69,118,667)	(69,118,667)
27	Solar Photovoltaic - PY1, PY2 & PY3	110,050,000		110,050,000
28	Electric Procurement/ERRA	4,655,881,839	440,558,675	5,096,440,514
29	GHG 2013 Deferred Cost		91,228,651	91,228,651
30	DWR--Power Charge/PCCBA	(124,455,827)	38,953,240	(85,502,587)
31	DWR Franchise Fees	2,755,439		2,755,439
32	LCPERMA		1,388,723	1,388,723
33	**Ongoing CTC/MTCBA**	33,463,792	16,402,104	49,865,896
34	**Cost Allocation Mechanism/NSGBA**	234,587,386	(16,354,094)	218,233,292
35	**ERB Balancing Account (ERBBA)**	14,400,000	(451,341,574)	(436,941,574)
36	**Nuclear Decommissioning**			
37	Nuclear Decommissioning Adjustment Mechanism (NDAM)	107,834,000	54,934,539	162,768,539
38	NDAM - Department of Energy Litigation Proceeds		(76,152,000)	(76,152,000)
39	**Public Purpose Programs**			
40	(1) Energy Efficiency (Formerly PGC)	120,862,411		120,862,411
41	(2) ESA (formerly known as LIEE) [5]	96,217,078		96,217,078
42	(3) PPPRAM		(14,589,033)	(14,589,033)
43	Electric Program Investment Charge (EPIC)	86,148,856	2,017,332	88,166,188
44	Procurement EE/PEERAM [5]	235,440,979	16,308,998	251,749,977
45	Statewide ME&O/PEERAM	(824,932)		(824,932)
46	CAREA [5]	12,945,574	(9,797,123)	3,148,451
47	**DWR Bonds**	409,748,219		409,748,219
48	**Total CPUC Jurisdictional**	12,014,302,259	153,494,435	12,167,796,694
49	**CPUC Revenues at Present Rates**			11,752,703,186
50	**Change in CPUC Jurisdictional**			415,093,508
51	**Total FERC Jurisdictional**			1,400,735,835
52	**FERC Revenues at Present Rates**			1,445,412,318
53	**Change in FERC Jurisdictional**			(44,676,483)
54	**Grand Total Projected Revenues**			**13,568,532,529**
55	**Total Revenues at Present Rates**			**13,198,115,504**
56	**Total Change**			**370,417,025**

Notes to Table 2:

1 Of the Pension revenue requirement, $93,891,000 is allocated to distribution and $52,994,000 is allocated to generation.

2 Of the FERABA projected revenue, $6,26,303 is allocated to distribution and $(1,331) is allocated to generation.

3 Of the SGPDPBA projected revenue, $(3,535,000) is allocated to distribution and $(3,097,000) is allocated to generation.

4 The balancing accounts of DRAM and UGBA reflect the 24 months amortization of projected year end balances, as described in Table 1

5 In addition to the approved 2015 RRQ for these programs, there is an addition for the employee benefit costs as approved in the 2014 GRC proceeding (OP39, D.14-08-032)

b. Natural gas revenue requirements are grouped into the following seven major categories: (1) Energy, (2) Distribution, (3) Backbone Transmission, (4) Local Transmission, (5) Public Purpose Programs, and (6) Gas Storage. For reference, an excerpt from the Advice 3547-G Annual Gas True-Up filed on December 23, 2014 is provided as Table 2. Below is a description of each gas revenue requirement category:

1) Energy contributes about 28 percent to the total gas revenue requirement. Authorized revenue requirement components include:
    - Gas supply portfolio costs
    - Interstate capacity costs
    - Gas hedging

2) Distribution contributes about 54 percent to the total authorized gas revenue requirement. It includes the 2014 General Rate Case, California Solar Initiative, and several other programs recovered through the distribution rate component.[3]

3) Backbone transmission gas revenue requirements include intrastate capacity costs and contribute approximately 5 percent to the total authorized gas revenue requirement.

4) Local transmission contributes approximately 5 percent to the total authorized gas revenue requirement.

5) Public Purpose Programs contributes about 6 percent to the total authorized gas revenue requirement. The revenue requirements include the CARE Discount collected from Non-CARE customers and Energy Efficiency program costs.

6) The gas storage revenue requirement contributes about 2 percent of the total authorized gas revenue requirement. It includes core customer gas storage, carrying cost of working gas in storage for core customers, and unbundled storage.

[3] The Gas Distribution revenue requirement reflects the CARE discount that is recovered through the CARE surcharge in the Public Purpose Program rate component. Correspondingly, Public Purpose Program revenue requirement reflects CARE discount revenue.

Table 2: Excerpt from Advice 3547-G Annual Gas True-Up filing for Gas Rates Effective January 1, 2015

Pacific Gas and Electric Company
San Francisco, California
U 39

	Revised	*Cal. P.U.C. Sheet No.*	31791-G
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	31455-G

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

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	
BASE REVENUES (incl. F&U) :									
Authorized GRC Distribution Base Revenue (1)								1,678,109	(I)
Pension (2)								50,422	(I)
Less: Other Operating Revenue								(25,228)	
Authorized Distribution Revenues in Rates	1,644,014	(I)	59,289	(I)				1,703,303	(I)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:									
G-10 Procurement-Related Employee Discount	(1,035)	(I)						(1,035)	(I)
G-10 Procurement Discount Allocation	408	(R)	627	(R)				1,035	(R)
Core Brokerage Fee Credit	(6,583)							(6,583)	
Distribution Base Revenue with Adj. and Credits	1,636,804	(I)	59,916	(I)				1,696,720	(I)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):									
Transportation Balancing Accounts	460,313	(I)	14,787	(R)				475,100	(I)
Self-Generation Incentive Program Revenue Requirement	2,587	(I)	3,938	(I)				6,525	(I)
CPUC Fee	1,970		1,240					3,210	
									(D)
									(D)
Franchise Fees and Uncollectible Expense (F&U) (on items above)	8,742	(I)	794	(R)				9,536	(I)
CARE Discount included in PPP Funding Requirement	(113,888)	(R)						(113,888)	(R)
CARE Discount not included in PPP Surcharge Rates	0							0	
Transportation Forecast Period Costs & Balancing Account Balances	359,724	(I)	20,759	(R)				380,483	(I)
GAS ACCORD REVENUE REQUIREMENT (incl. F&U) (4):									
Local Transmission	138,046	(I)	78,398	(I)				216,444	(I)
Customer Access Charge – Transmission			5,127	(I)				5,127	(I)
Storage	49,201	(I)			35,030	(I)		84,231	(I)
Carrying Cost on PG&E Working Gas in Storage	2,414	(I)			649	(I)		3,063	(I)
Backbone Transmission/L-401	98,132	(I)			137,996	(I)		236,128	(I)
Gas Accord Revenue Requirement	287,793	(I)	83,525	(I)	173,675	(I)		544,993	(I)

(1) The amount includes the authorized distribution base revenue and F&U approved effective January 1, 2014, in GRC D.14-08-032.

(2) Pursuant to D.09-09-020, PG&E will maintain the annual contribution to the Company's retirement plan trust fund at the adopted 2013 amount.

(3) The total 2014 SGIP revenue requirement (RRQ) was authorized in D.14-12-033. (T)

(4) The Gas Accord V RRQ was adopted in D.11-04-031. Storage revenues allocated to load balancing are included in unbundled transmission rates. Some amounts include changes to PG&E's cost of capital authorized in D.12-12-034. The backbone transmission amounts include the implementation of the AB32-related gas compressor station costs (D.13-03-017).

*Some numbers may not add precisely due to rounding.

(Continued)

Advice Letter No: 3547-G	*Issued by*	*Date Filed*	December 23, 2014
Decision No. 05-06-029	***Steven Malnight***	*Effective*	January 1, 2015
	Senior Vice President	*Resolution No.*	
2C13	*Regulatory Affairs*		

Table 2 (continued.): Excerpt from Advice 3547-G Annual Gas True-Up filing for Gas Rates Effective January 1, 2015

PG&E	*Pacific Gas and Electric Company* *San Francisco, California* U 39		Revised	*Cal. P.U.C. Sheet No.* 31792-G
		Cancelling	Revised	*Cal. P.U.C. Sheet No.* 31456-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 (5):						
Illustrative Gas Supply Portfolio				970,172 (R)	970,172 (R)	
Interstate and Canadian Capacity				155,602 (R)	155,602 (R)	
						(D)
F&U (on items above and Procurement Account Balances Below)				19,620 (R)	19,620 (R)	
Backbone Capacity (incl. F&U)	(67,294) (R)			67,294 (I)	0	
Backbone Volumetric (incl. F&U)	(30,838) (R)			30,838 (I)	0	
Storage (incl. F&U)	(49,201) (R)			49,201 (I)	0	
Carrying Cost on PG&E Working Gas in Storage (incl. F&U)	(2,414) (R)			2,414 (I)	0	
Core Brokerage Fee (incl. F&U)				6,583	6,583	
Procurement Account Balances				- (R)	- (R)	
Illus. Core Procurement Revenue Requirement	(149,747) (R)			1,301,724 (R)	1,151,977 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	**2,134,574** (I)	**164,200** (R)	**173,675** (I)	**1,301,724** (R)	**3,774,173** (I)	
IMPLEMENTATION PLAN REVENUE REQUIREMENT (7)						
Implementation Plan – Local Transmission	0 (R)	0 (R)			0 (R)	
Implementation Plan – Backbone	0 (R)	0 (R)			0 (R)	
Implementation Plan – Storage	0 (R)	0 (R)			0 (R)	
Total Implementation Plan	**0** (R)	**0** (R)			**0** (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):						
Energy Efficiency (EE)	69,554 (I)	7,742 (I)			77,296 (I)	
Energy Savings Assistance (ESA)	61,961 (I)	6,897 (I)			68,858 (I)	
Research, Demonstration and Development (RD&D)	6,715 (R)	3,779 (R)			10,494 (R)	
CARE Administrative Expense	1,811 (I)	1,190 (I)			3,001 (I)	
Statewide Marketing, Education & Outreach – Phase 2	(429) (R)	(48) (R)			(477) (R)	(T)
BOE and CPUC Administrative Cost	260 (I)	146 (I)			406 (I)	
PPP Balancing Accounts	4,526 (I)	(6,266) (I)			(1,740) (I)	
CARE Discount Recovered from non-CARE customers	68,733 (I)	45,155 (I)			113,888 (I)	
Total PPP Funding Requirement in Rates	**213,131** (I)	**58,595** (I)			**271,726** (I)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	**2,347,705** (I)	**222,795** (R)	**173,675** (I)	**1,301,724** (R)	**4,045,899** (I)	

(5) 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 is an annual illustrative amount. Actual gas commodity costs change monthly.

(6) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2015 PPP surcharge AL 3528-G; and includes ESA program funding adopted in D.14-08-030, EE program funding adopted in D.14-10-046, CARE annual administrative expense adopted in D.14-08-030, and excludes F&U per D.04-08-010. (T) (T)

(7) The Pipeline Safety Implementation Plan was authorized in D.12-12-030 and updated in D.14-11-023. The decrease in the total PSEP revenue requirements is incorporated in the Core Gas Pipeline Safety Balancing account (CGPSBA) and Noncore Pipeline Safety Balancing Account (NGPSBA), which are included in the Transportation Balancing Account amount shown above. (T) I (T)

(Continued)

Advice Letter No:	3547-G	*Issued by*	*Date Filed*	December 23, 2014
Decision No.	05-06-029	***Steven Malnight***	*Effective*	January 1, 2015
		Senior Vice President	*Resolution No.*	
3C17		*Regulatory Affairs*		

6. Description of Gas and Electric Rate Components

The revenue requirements discussed in the previous section directly align with rate components. At the highest level, electric and gas rates can be described as revenue requirement divided by sales. Therefore, both revenue requirement changes and sales variations impact the actual rates for gas and electric service. The rate pressures created by revenue requirement increases are moderated when sales are also forecasted to increase. Adjustments in the allocation of revenue requirements across customer classes and rate tiers also impact the rates experienced by individual customers. Table 3 below provides a summary of electric and gas revenue requirements.

Table 3: Summary of Revenue Requirements and Percentage of Total Revenue as of January 1, 2015

RATE COMPONENT	Electric Revenue Requirement $M	%	Gas Revenue Requirement $M	%
Energy and Generation	$7,257	53%	$1,145	28%
Competition Transition Charge	268	2%	-	-
Distribution (1)	3554	26%	2180	54%
Energy Recovery Bonds and Department of Water Resource Bonds	-27	0%	-	-
Gas Transmission / Backbone			206	5%
Electric Transmission	1401	10%		
Local Transmission (Gas)	-	-	190	5%
Public Purpose Programs (2)	1029	8%	242	6%
Nuclear Decommissioning	87	1%	-	-
Gas Storage	-	-	82	2%
Total Authorized Revenue Requirement	$13,569	100%	$4,046	100%

(1) Includes 2015 CARE discount of approximately $484million for electric.
(2) Includes 2015 CARE discount of approximately $114million for gas which is collected in Public Purpose Program rates.
(3) As of January 1, 2015. Values are approximated to the nearest million.

7. Load/Demand Forecasts

Customer sales volatility over time directly impacts rates for gas and electric customers. PG&E updates sales forecasts for its service territory on a regular basis, the updated sales forecasts are typically filed in conjunction with rate change filings with the Commission. In the past, aggregate customer sales typically increased at a pace which partly offset annual increases to the revenue requirement. However, as a result of the recession, the increase in distributed generation, as well as continued savings from energy efficiency, PG&E is just now returning to sales on par with the peak in 2008. Fixed costs have been spread across lower sales resulting in higher rates for most customers. The following sections discuss the forecast trends for electric and gas sales for 2015.

a. Electric

According to Moody's Analytics economic forecast for PG&E service territory, PG&E service territory is, "at the vanguard of the U.S. Expansion."[4] Strong growth in high wage jobs such as technology and business services, primarily in the Bay Area, has boosted the overall economy, including commercial construction and home prices. The economy in the service territory should continue to grow more quickly than the U.S. economy, and inland counties should enjoy more spillover growth due to quickly rising living costs in the coastal areas. Despite strong economic growth, PG&E has not experienced the concomitant rise in sales historically associated with a booming economy. Since 2012 PG&E's sales have only grown about 0.5 percent a year. This decoupling of energy sales from economic growth is associated with continued gains in energy efficiency from new codes and standards as well as utility programs, and the growth of distributed generation, primarily rooftop solar. In the residential sector, average use per customer has fallen from approximately 575 kWh at its peak in 2006 to 530 kWh per customer today. The small and medium commercial sector has dropped from about 5,350 kWh per customer at its peak in 2007 to just over 5,050 kWh per customer today. Only the growing number of customers has kept sales from falling more significantly.

Demand in some sectors is growing. In 2013 - 2014, increased groundwater pumping by the drought-afflicted farm sector drove record agricultural sector electric sales. With a dry winter in progress, we expect agricultural sales to continue to climb in 2015. Our industrial customers posted strong sales gains in 2014, growing at approximately 3 percent over 2013, primarily due to improved economic conditions.

Overall, PG&E's electric sales increased by 0.4 percent in 2014 over 2013, driven primarily by growing agricultural and industrial sales. Assuming normal weather conditions and the continued growth of energy efficiency and distributed generation, PG&E expects a decrease in electric sales between 2014 and 2015.

b. Gas

The total demand for gas was unusually low, declining by about 3 percent in 2014 due to very mild winter weather conditions. While total demand for gas is expected to recover some of this decrease due to returning to normal weather conditions in 2015, expected gas rate increases during the next three years, coupled with energy efficiency program impacts, will result in lower gas demand levels than prior years.

Core customers use natural gas primarily for space and water heating. Thus, core customer gas sales typically require an increase in the customer base to drive an increase in usage. As the U.S. economy grows stronger, especially in the PG&E service territory, this will put upward pressure on natural gas demand but counterbalancing that will be the continuing improvements in the utilization of gas within the residential, commercial and industrial buildings which will slow down that expected increase in gas demand.

In contrast to core customers, the demand for natural gas used in electric generation has been very high during the last three years mainly driven by dry weather causing low hydroelectric

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[4] Moody's Analytics December 2014 Précis.

generation as well as other factors such as new generation facilities coming online – driven in part by Community Choice Aggregation efforts to bring on cleaner energy sources - and reductions in nuclear generating capacity. Demand for natural gas use for electric generation is expected to decrease assuming normal weather conditions for hydroelectric generation and expected rate increases take place through 2017. After that, the overall trend will begin to show a modest positive growth.

Although still comparably low to other sectors, the forecast for Natural Gas Vehicles shows a strong increase in the future. The increase reflects consumer interest in selecting a greener energy source for transportation.

Appendix: Outlook from May 1, 2015 to April 30, 2016.

Please see the table below for a list of PG&E's expected significant rate changes for 2015- 2016. The table reflects currently anticipated rate filings schedule for 2015 and the revenue requirement or rate components that are primarily affected by each filing. This is not an exhaustive list of PG&E's filings; rather it incorporates planned regulatory filings which are known at this time and are expected to have a rate impact for PG&E's electric and/or gas customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized or settled are subject to change through the normal regulatory approval processes of the CPUC and other regulatory agencies.

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2015 RRQ *	2016 RRQ *			
	<u>Q3 2010</u>									
1	Default Residential Rate Programs (Peak Day Pricing)	A.10-08-005	August 9, 2010	TBD	TBD	TBD	TBD	Per D.08-07-045, Ordering Paragraph (OP) 8, by August 9, 2010, PG&E needs to file an application proposing a default Critical Peak Pricing (CPP) rate for residential customers, subject to their ability to opt-out of the CPP rate. Amounts shown reflect PG&E's 2010 filed position. Should the CPUC decide to move forward on this application, amounts would need to be updated.	Electric	Distribution
	<u>Q4 2011</u>									
2	Rate Design Window 2010/Peak Time Rebate (Revised Testimony)	A.10-02-028	October 28, 2011	TBD	TBD	TBD	TBD	Requests approval for PTR program that provides incentives for customers to respond to price signals on event days when demand is expected to be high. Should the CPUC decide to move forward on this application, amounts would need to be updated.	Electric	Distribution
	<u>Q1 2012</u>									
3	Market Redesign and Technology Upgrade (MRTU) 2010 (re-filing)	A.12-01-014	January 31, 2012	TBD	67.5	N/A	67.5	Request for recovery of costs PG&E incurred for projects that became operative in 2010, to comply with the mandated MRTU initiatives and a forecasted revenue requirement for 2012 and 2013.	Electric	Distribution; Generation

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions) Total Cost	2015 RRQ *	2016 RRQ *	Description	Affected Rate	Affected Rate Component
	Q2 2012									
4	Market Redesign and Technology Upgrade 2011	A.12-04-009	April 16, 2012	TBD	7.9	N/A	7.9	Request for recovery of costs PG&E incurred for projects that became operative in 2011, to comply with the mandated MRTU initiatives.	Electric	Distribution; Generation
	Q1 2013									
5	ERRA Compliance 2012 (incl. MRTU and Diablo Canyon Seismic Studies)	A.13-02-023	Feb 28, 2013	TBD	25.5	N/A	25.5	Annual proceeding to review the utility-owned generation operations, economic dispatch of electric resources, utility retained generation fuel procurement, and entries to the ERRA balancing account for the 2012 record period. Additionally, CPUC ordered PG&E to include review of incremental costs and cost recovery proposal of MRTU projects and Diablo Canyon Seismic Studies projects.	Electric	Generation
	Q2 2013									
6	2014 GRC, Phase 2	A.13-04-012	April 18, 2014	TBD	N/A	N/A	N/A	PG&E's electric marginal cost, revenue allocation and rate design proposals for 2014.	Electric	Distribution; Generation; PPP
	Q4 2013									
7	2015 Gas Transmission & Storage Rate Case	A.13-12-012	December 19, 2013	10/1/2015		1,286	61	The GT&S rate case sets the rates, terms and conditions of service for PG&E's gas transmission (backbone and local transmission) and storage business.	Gas	Backbone Transmission; Local Transmission; Storage;

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Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2015 RRQ *	2016 RRQ *			
										Customer Access Charge (CAC)
	Q1 2014									
8	2013 ERRA Compliance Review (incl. MRTU, DCSSBA and RPS-related consulting fees)	A.14-02-008	2/28/14	3/1/2016	7.9	N/A	7.9	Annual proceeding to review the utility-owned generation operations, economic dispatch of electric resources, utility retained generation fuel procurement, and entries to the ERRA, MRTU and Diablo Canyon Seismic Studies balancing accounts for the 2013 record period.	Electric	Generation
	Q2 2014									
9	Demand Response /Rule 24 Cost Recovery Application	A.14-06-001	June 2014	1/1/2016	TBD	N/A	TBD	Per D.12-11-025, PG&E will file an application to request recovery of costs to implement the direct participation of Demand Response resources in CAISO wholesale markets. This application will forecast the capital and expenses that PG&E will incur, so Demand Response resources may be bid into wholesale electricity markets.	Electric	Distribution
10	CPIM 2013 Annual Report (Yr. 20)	N/A	June 13, 2014	Q2 2015		1	N/A	Compliance report for gas core procurement incentive mechanism for November 1, 2012 through October 31, 2013.	Gas	Procurement

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2015 RRQ *	2016 RRQ *			
	Q4 2014									
11	2015-2017 Energy Savings Assistance Program and California Alternate Rates for Energy Application	A.14-11-010	November 2014	1/1/2015	TBD	181	177	Application seeking approval of PG&E's proposed Energy Savings Assistance (ESA) program and California Alternate Rates for Energy (CARE) administrative activities and budgets for 2015-2017. The ESA and CARE programs are statutorily established programs that provide assistance to qualifying low-income customers. Gas and Electric allocation for 2015: ESA 58%-e/42%-g; CARE 81%-e/19%-g; for 2016: ESA52%-e/48%-g., CARE 80%-e/20%-g.	Electric; Gas	Electric PPP; Gas PPP
12	2015 Rate Design Window	A.14-11-014	November 25, 2014	Q1 2016	N/A	N/A	N/A	In this application PG&E requested authority to update both the peak and off-peak TOU periods, as well as the winter and summer season definitions applicable to its residential Schedule E-TOU	Electric	Distribution; Generation
	Q1 2015									
13	GHG OIR Phase II	R.14-03-003	January, 2015	1/1/16		N/A	TBD	On March 19, 2014, the Commission issued a rulemaking (R.14-03-003) to establish policy, programs, rules and tariffs necessary for natural gas utilities to comply with the California Air Resources Board's (ARB) Greenhouse Gas (GHG) Cap-and-Trade Program. The primary focus will be on the	Gas	Distribution

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2015 RRQ *	2016 RRQ *			
								treatment of GHG Cap-and-Trade compliance costs (natural gas supplier costs) and revenues associated with the Cap-and-Trade Program.		
14	Solar PV Program Incentive Award	D.14-11-026	Q1 2015	1/1/2016	TBD	N/A	TBD	Per OP 2 of D.14-11-026, PG&E shall file a Tier 2 Advice Letter establishing eligibility for any cost-savings incentives authorized by Ordering Paragraph 4 of Decision 10-04-052 for the UOG portion of the Solar Photovoltaic Program.	Electric	Generation
15	Electric Vehicle Infrastructure and Education Program	TBD	Q1 2015	1/1/2016	TBD	N/A	TBD	This is a request for PG&E to build and own electric vehicle charging station infrastructure in PG&E's service territory.	Electric	Distribution
16	2014 ERRA Compliance Review (incl. DCSSBA and RPS-related consulting fees)	TBD	February 27, 2015	3/1/2016	9	N/A	9	Annual proceeding to review the utility-owned generation operations, economic dispatch of electric resources, utility retained generation fuel procurement, and entries to the ERRA and Diablo Canyon Seismic Studies balancing accounts for the 2014 record period.	Electric	Generation
	<u>Q2 2015</u>									
17	CPIM 2014 Annual Report (Yr. 21)	N/A	April 2015	TBD			TBD	Compliance report for gas core procurement incentive mechanism for November 1, 2013 through October 31, 2014.	Gas	Procurement
18	ERRA 2016 Forecast	TBD	June 2015	1/1/2016	TBD	N/A	TBD	An annual application that requests approval of PG&E's forecasted procurement related revenue requirement, including Energy Resource	Electric	Generation; CTC; NSGC; PCIA

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2015 RRQ *	2016 RRQ *			
								Recovery Account (ERRA) and non-bypassable charges – Ongoing Competition Transition Charge (CTC), Power Charge Indifference Amount (PCIA) and Cost Allocation Mechanism (CAM) non-bypassable charges.		
	<u>Q3 2015</u>									
19	Transmission Owner 17	FERC Docket No. TBD	July 2015	3/1/2016	TBD	N/A	TBD	Annual filing to recover transmission costs.	Electric	Transmission
20	Energy Efficiency Risk-Reward Incentive Mechanism (RRIM) OIR	R.12-01-005	PG&E to File Tier 3 Advice Letter by Q3 2015 with Commission approval by Q4 2015 for approval of 50% of 2013 and 50% of 2014 Program years Incentive Award	1/1/2016		N/A	TBD	Rulemaking to address modifications to the Energy Efficiency Incentive for the 2010-2012 program cycle, 2013-2014 program cycle, and beyond.	Electric; Gas	Electric Distribution; Gas Transportation
	<u>Q4 2015</u>									
21	2016 FERC Rate Filing for Annual Updates to the Transmission Balancing Accounts	FERC Docket No. TBD	October 2015	1/1/2016		N/A	TBD	PG&E annually files with the Federal Energy Regulatory Commission (FERC) requesting a transmission rate change for its retail electric customers, in compliance with Resolution E-3930. The purpose of PG&E's FERC filing is to request the annual update to the Transmission Revenue Balancing	Electric	Transmission

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2015 RRQ *	2016 RRQ *			
								Account Adjustment, the Reliability Services rates and the End-Use Customer Refund Balancing Account Adjustment, for an effective date on or after January 1 of each year.		
22	2016 Public Purpose Programs Surcharge Rate Advice Letter	TBD	October 2015	1/1/2016		N/A	TBD	Annual filing for cost recovery of gas public purpose programs, gas research and demonstration, and Board of Equalization administrative costs.	Gas	PPP
23	Transmission Access Charge Balancing Account Adjustment (TACBAA)	FERC Docket No. TBD	December 2015	3/1/2016		N/A	TBD	The TACBAA is a ratemaking mechanism designed to ensure that the difference in the amount of costs billed to PG&E as a load-serving entity and the revenues paid to PG&E as a Participating Transmission Owner under the California Independent System Operator Corporation Tariff is recovered from or returned to PG&E's End-Use customers.	Electric	Transmission
24	2016 Annual Gas True-Up (AGT) Advice Letter (Tier 2 Preview) and 2016 AGT Advice Letter (Tier 1 Final)	TBD	November 2015 and December 2015	1/1/2016		N/A	TBD	Annual filing consolidating gas transportation rate changes authorized by the CPUC and true-up of balancing account balances. This filing will be supplemented in December.	Gas	Distribution; Backbone Transmission; Local Transmission; Gas Storage; CAC
25	2016 AET Advice Letter and Supplemental	TBD	September 2015 and December 2015	1/1/2016		N/A	TBD	Annual filing to adjust for balancing account over/under collections, and consolidation of electric revenue requirements adopted by the CPUC.	Electric	CTC; Distribution; DWR; ECRA; Generation;

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implemen-tation date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2015 RRQ *	2016 RRQ *			
	Advice Letter filing							This filing is supplemental in December.		NSGC; ND; PPP; PCIA; Transmission