Pacific Gas and Electric Company

Pursuant to the requirements of Senate Bill (SB) 695, which was codified into Public Utilities Code Section 913.1, 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 taken 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 2016 and beyond.

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

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 poses challenges, in part 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 where that allocation among customers may in some cases also be mandated by law.

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. In 2013, the Governor signed into law Assembly Bill (AB) 327, which removed many 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 that has no cost-of-service basis. While some progress has been made, PG&E's upper-tier residential rate effective March 1, 2016, remains at 37.4 cents per kWh, far in excess of cost of service and among the highest of the large investor-owned utilities (IOUs) in the country. Usage above twice the baseline amount is still being charged more than double the 18.2 cents per kWh charged for baseline usage.[1]

The Commission in Decision (D.) 15-07-001 adopted a "glide path" trajectory to get to two Tiers with usage for Tier 2 exceeding 100% of baseline and declining price ratios

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1 Baseline usage varies for different customers depending on their location (climate zone) and type of service (basic or all-electric). Effective March 1, 2016, PG&E's top tier is Tier 3, for usage in excess of twice the baseline amount.

between Tiers 1 and 2, reaching a 1.25 to 1 ratio in 2019. However, there is uncertainty about when that ratio will actually be achieved due to the adoption of a cap on increases to Tier 1 rates.[2] Moreover, the Commission's decision also implemented a "super user of electricity (SUE) surcharge" to be applied to usage above 400% of baseline and specified implementation by 2017 with a glide path trajectory between the ratios of the rates charged for SUE versus Tier 1 of 2.19 to 1 in 2019. Rate differentials this large have no cost basis.[3] Finally, while not yet implementing a fixed monthly charge to recover fixed costs that do not vary with usage as permitted by AB 327, D.15-07-001 did allow work to proceed on a methodology for developing such a charge, which is now scheduled to occur in Phase 2 of PG&E's upcoming 2017 General Rate Case (GRC). PG&E supports having a fixed monthly charge in residential rates, consistent with rate design policies adopted by public utility regulators around the country as well as similar to fixed monthly charges that have been in all of PG&E's non-residential rates for years, as a more cost-based rate design that will spread costs to customers in a more equitable way based on the fixed costs to serve them.

A second challenge to equitable rates for customers is the overall cost-shift associated with customer-owned generation, particularly residential generation participating 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[4]. NEM rates compensate customers who install renewable on-site generation well in excess of the market-based costs of renewable generation otherwise paid by PG&E or charged by non-NEM renewable suppliers. As a result, NEM customers do not pay all their fixed costs associated with accessing the grid and receive a windfall in the form of revenues for exported power far in excess of market prices. These fixed and above-market costs are instead shifted to customers for whom roof-top generation may not be feasible, affordable or desired.

Mandated residential rate designs have magnified the impact of the cost-shift associated with customer-owned generation. Upper-tier sales continue to be charged rates well in excess of cost of service, which exacerbates the cost-shift when large users install solar systems. This inequity is also regressive from a social policy perspective when the rooftop solar systems are owned by customers with higher than average incomes.

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2 That cap on Tier 1 rate increases has already caused PG&E to be unable to hit the Commission's specified 2016 glide path rate ratios in its March 1, 2016 rate change.

3 The introduction of the SUE tier also means that the rate structure will still have three tiers, contrary to the objective of simplifying rates and making them more equitable for all residential customers. This will also greatly increase bill volatility for customers with usage in the SUE tier.

4 The recent NEM decision did require customers to pay certain non-bypassable charges on all usage not offset by on-site generation, reducing some of this cross-subsidization.

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 nascent solar market.

However, the solar market has now 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. These subsidies must be reformed to *sustainably* accommodate continued growth in customer-owned generation for the benefit of all customers, including non-participants.

AB 327 also addressed cost-shifting resulting from NEM, directing the Commission, by the end of 2015, to adopt a NEM successor tariff that protects the interest of non-participating customers (i.e., those without solar) by ensuring the benefits of NEM approximately equal the costs. PG&E, the other two IOUs, the Office of Ratepayer Advocates, and The Utility Reform Network submitted proposals that, while adopting different approaches, all would have significantly reduced the cost-shifting from NEM. However, D. 16-01-044, issued by the Commission on February 5, 2016, deferred significant reforms of the cost-shifting resulting from NEM, contrary to AB 327.Thus, rates and bills for those without solar will continue to rise. Energy Division analysis using the Public Tool shows that by 2025, if NEM is not meaningfully changed, the costs incurred by other customers to subsidize solar customers will total $3.6 to $5 billion per year, adding $252 to $288 to the annual bill of an average PG&E non-CARE residential customer, and $156 to $180 to the annual bill of an average PG&E CARE customer.[5] These are the Energy Division bookend results using its assumptions; PG&E's estimate of the cost shift is substantially higher.

PG&E believes that residential rate design and NEM reforms 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's rate policy focuses on providing customers with reasonable rates by minimizing the number of rate changes per year and smoothing the impact of revenue and rate changes for its customers.

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5 The 2025 cost shift figures are from Table 3 of PG&E's Comments on Party Proposals filed September 1, 2015 in R.14-07-002, at p. 10. The bill impacts are calculated from the Rate Output Table of Public Tool "Results" tab for each respective scenario. See also PG&E's Opening Comments on Proposed Decision dated January 7, 2016, at pp. -12.

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 later in the year). 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 changes in gas transportation and Public Purpose Program costs.

PG&E undertakes efforts to manage the timing of revenue changes and subsequent rate changes to smooth the impact on both electric and gas customers. An example is PG&E's implementation of Decision 14-08-032, 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. To mitigate the impact of the change on gas rates, 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 significant 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 25 years has increased at a lower rate than the service territory's consumer price index (CPI) growth.

Figure 1: Historic Service Territory CPI[6] vs. System Average Bundled Electric Rate

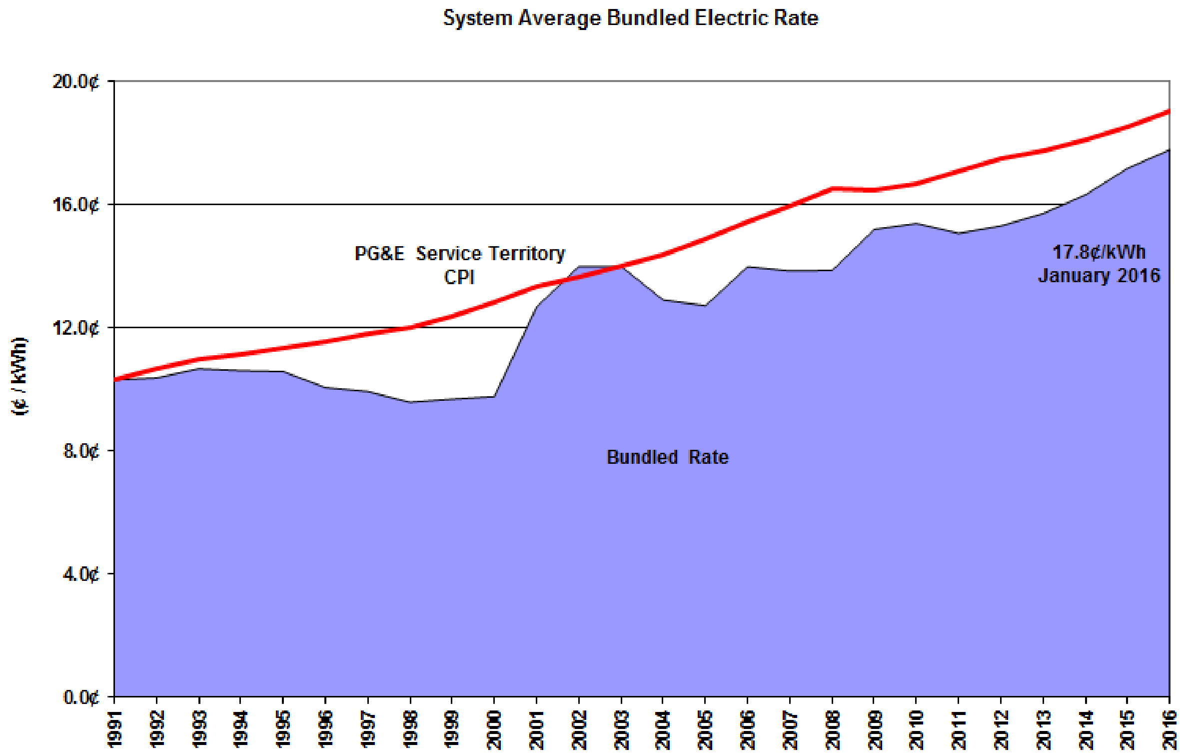
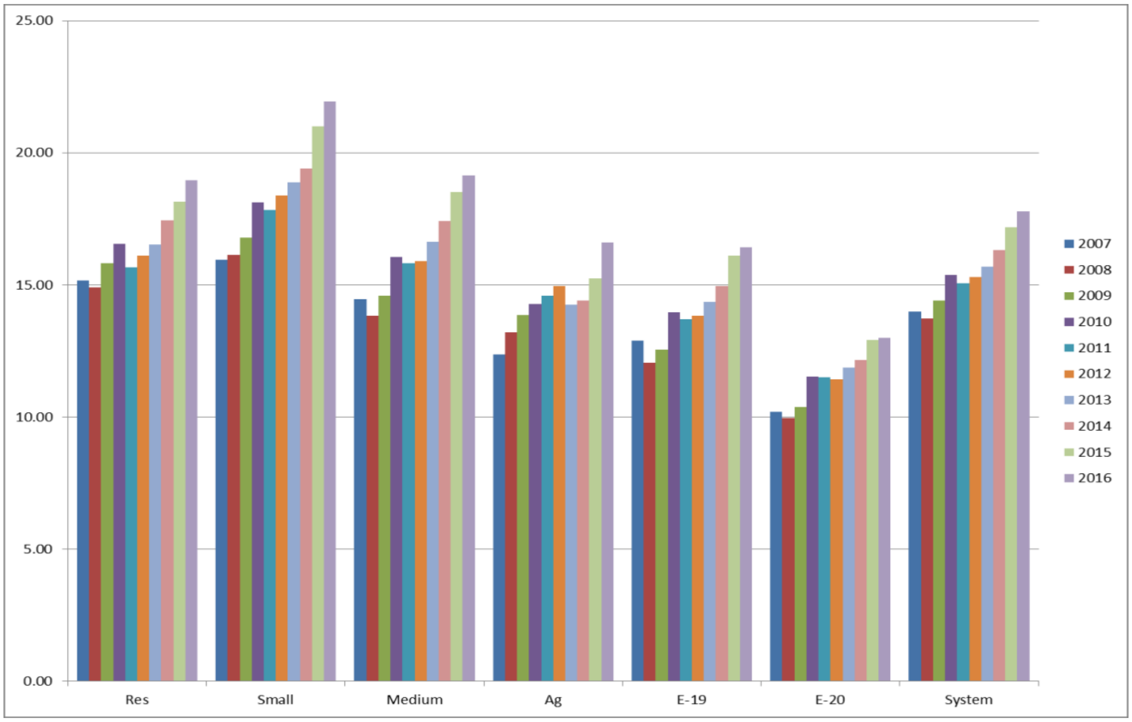


Figure 2 below shows a breakdown of the system average rate by customer class for the 2007-2016 period. Each class shows the same upward trend as the system average rate over this period, with the residential and small and medium business customers generally having higher average rates than the system average and the large industrial and agricultural customers generally having lower average rates.

[6] CPI provided by Economy.com

Figure 2: Historic average rates by class (2007 – 2016)



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, 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.

Also, beginning in 2011 and continuing through 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, partially funded by shareholders, 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. In October 2013, PG&E filed its Pipeline Safety Enhancement Plan (PSEP) update and on November 20, 2014, the CPUC issued Decision 14-11-023, approving the Settlement Agreement as proposed by PG&E, ORA and TURN, which included no reduction in the proposed scope of work described in PG&E's PSEP Update application and a $76 million reduction in revenue requirements for the period 2012-2014 which was included in customer rates in January 2015. Post-2014 recovery of the ongoing PSEP revenue requirement related to authorized PSEP capital expenditures will be addressed in PG&E's 2015 Gas Transmission and Storage Rate Case.

PG&E's 2014 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.

PG&E currently has pending before the CPUC its 2017 GRC, filed in September 2015. The filing supports investments to further build upon improvements to the safety and reliability of the system, while also supporting California's goals to be the leader in renewable energy and emerging energy technologies. Initiatives included in the 2017 GRC include: smart grid technologies that better integrate and manage more rooftop solar and renewable energy, as well as enable a growing array of other technologies, from electric vehicles to smart appliances and battery storage; emergency preparedness for major disruptions like earthquakes, including construction of a backup gas control center; stronger prevention and management of wildfires through increased patrols and new laser-based technology; advanced mobile technology to provide field workers with the tools to get work done more effectively and efficiently; and, faster response times to customer calls about possible gas leaks. As described in Section 4 below, while PG&E's plans include significant safety and reliability investments, the company is mindful of the need to balance these important initiatives with maintaining overall rates at a reasonable level. Throughout its 2017 GRC filing, PG&E describes its initiatives to improve the efficiency of its operations.

PG&E also has pending before the CPUC its 2015 Gas Transmission and Storage (GT&S) rate case, filed in December 2013. In this application, PG&E requested CPUC authorization to recover forecasted costs 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 when developing and implementing safety plans consistent with the best practices in the utility industry. If approved, PG&E's 2015 GT&S rate case will enable PG&E to implement a vintage pipe replacement program, perform hydrostatic testing of approximately 170 miles of pipe each year and add 516 miles capable of being "made piggable" to accommodate in-line inspection tools. In a subsequent phase, the CPUC will determine which programs adopted in the Phase I Decision meet the safety related criteria established in the San Bruno penalty decision and should be funded by shareholders ($850 million).

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 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 they raise electric and gas rates or restrict the ability of utilities to manage or mitigate costs, the Legislature and Commission should then periodically review these mandates and policies to ensure 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 have been excluded from receiving GHG allowance credits. Consequently, nonresidential and non-"emissions-intensive trade exposed" customers with demands greater than 20 kilowatts do not have their bill increases mitigated. In addition, development of an RPS procurement expenditure limitation is anticipated to be addressed in the Renewables Portfolio Standard OIR (R.11-05-005).

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, GHG emissions reductions, and encouragement of 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, NEM encourages customer adoption of solar generation but shifts costs onto other non-participating customers. These cost shifts or subsidies may have been warranted as a policy when the solar industry was in its infancy and the cost-shift was relatively small; however the solar industry is no longer in its infancy, the cost-shift has grown significantly, and the subsidies are no longer warranted. Similarly, the Legislature determined that the cost to support low-income CARE customers, which in PG&E's case grew to more than $750 million a year, was unsustainable. As a result, AB 327 mandated 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 continually looks for opportunities to identify and implement efficiencies to minimize costs and the potential for rate increases. Some of the initiatives planned or currently underway and that are or will be reflected in filings before the CPUC (e.g., 2017 General Rate Case and 2015 Gas Transmission and Storage rate case) and Federal Energy Regulatory Commission (FERC) (e.g., PG&E's Transmission Owner Tariff rate cases) include:

- Electric Transmission and Distribution (T&D) Operations – PG&E has deployed a number of work efficiency initiatives to offset cost increases including increasing field productivity through improved work scheduling and leveraging technology to improve operational efficiency and resource utilization in its electric distribution operations. Additionally, in coordination with the California Independent System Operator (ISO) through the transmission planning process (TPP), PG&E is evaluating the need for transmission capacity projects that have already been approved through the TPP to validate the need in light of current and updated load growth forecasts. If the trends continue, PG&E would expect that fewer transmission capacity projects will be needed to meet system needs.

- Gas T&D Operations – PG&E has identified a number of efficiency and continuous improvement efforts to reduce, among other things, the cost of addressing leaks through the use of new technology and new processes in its gas distribution operations. PG&E's gas transmission and storage operations are focused on a rigorous risk-based asset management strategy and investment planning process and has implemented project governance and controls to manage project execution and deliver large scale projects in a timely, cost effective and high quality manner.

- SmartMeter Technology – PG&E continues to achieve cost savings related to the deployment of SmartMeter technology, including the ability to remotely read meters, to connect and disconnect customers remotely, and to determine whether power has been restored after an outage without requiring a field visit.

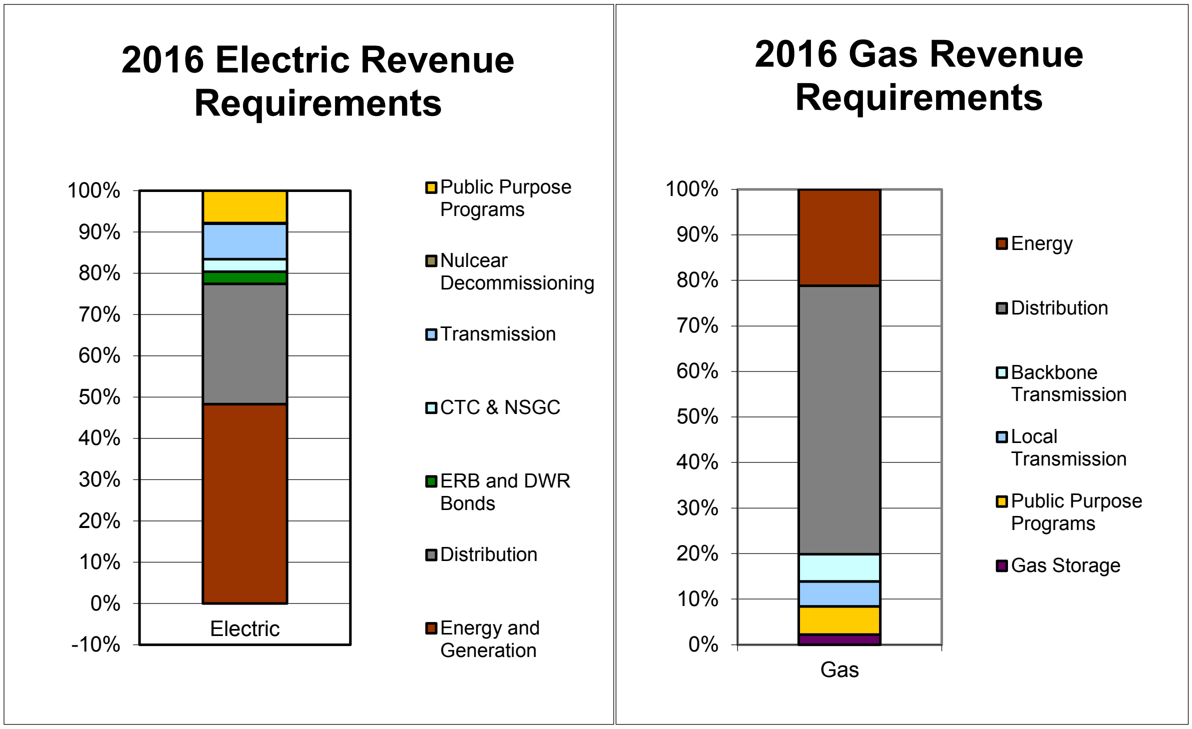
- Support Organizations – PG&E's building services organization has launched a number of initiatives to consolidate and better utilize existing buildings to reduce costs in the long run. Similarly, the company's information technology and human resource departments have identified a number of efficiencies to drive down technology costs across the enterprise.

These efforts and others will help the company reduce the upward pressure on the rates paid by customers.

5. Description of Revenue Requirements

A description of PG&E's authorized electric and gas revenue requirement categories and the percent contribution to the total revenue requirement as of January 2016 is provided separately. The key categories of revenue requirements are based on PG&E's major rate components.

Figure 3: 2016 Revenue Requirement Categories



a. Electric revenue requirements are grouped into the following major rate categories: (1) Energy and Generation, (2) Distribution, (3) Energy Recovery Bonds and Department of Water Resources bonds, (4) Competition Transition Charge and New System Generation Charge, (5) Transmission, (6) Nuclear Decommissioning, and (7) Public Purpose Programs. Below is a description of each electric revenue requirement category:

1) Energy and Generation contribute approximately 48 percent to the total authorized electric revenue requirement in 2016. Through the Generation rate component, PG&E recovers the costs of its generation portfolio which include the cost of PG&E's utility-owned generation (UOG) consisting of the fuel, base Operations and Maintenance (O&M) and capital-related revenue requirements associated with its nuclear, solar, gas, and hydro plants. Energy costs also include amounts related to long-term power contracts entered into by the DWR on behalf of the state's IOUs. In addition, PG&E recovers all of its purchased power costs required to meet its load. The purchased power costs include the costs of Qualifying Facilities, and all other bilateral contracts that PG&E has entered into when the company was authorized to resume the power procurement function and make purchases and sales through the wholesale markets. The impact of renewable contracts entered into to meet the RPS and GHG costs are also reflected in generation rates.

2) Distribution contributes approximately 29 percent to the total authorized revenue requirement in 2016. The electric distribution revenue requirement includes the

base distribution O&M costs and capital-related revenue requirement, California Solar Initiative, Demand Response, return of proceeds resulting from the cap-and-trade market, and other programs.[7]

3) Energy Recovery Bond (ERB) and Department of Water Resources (DWR) Bond contribute approximately 3 percent to the total authorized revenue requirement in 2016. The ERB is now used to return amounts to customers resulting from settlement agreements with sellers of energy to resolve energy claims related to the Western Energy Crisis of 2000-2001. DWR Bond is a charge that pays for bonds issued by DWR to cover the cost of purchased power during the energy crisis.

4) Competition Transition Charge (CTC) and New System Generation Charge (NSGC) contribute approximately 3 percent to the total authorized revenue requirement in 2016. CTC recovers uneconomic (above market) costs resulting from California's electric industry restructuring pursuant to Public Utilities Code Section 367(a). Specifically, costs associated with power purchase contract obligations that were in rates prior to December 20, 1995 continue to be recoverable from non-exempt departing load for the duration of the contract. NSGC recovers the net capacity cost and allocates the resource adequacy benefits associated with resources the Commission has determined provide system and/or local reliability benefits to load serving entities in the IOU's service territory. In addition, net capacity costs associated with new generation authorized under the Qualifying Facility and Combined Heat and Power Settlement are also recovered via the Cost Allocation Mechanism.

5) Electric Transmission contributes 9 percent to the total authorized revenue requirement in 2016. Transmission revenue requirements include the following:

- Base Transmission which recovers the O&M and capital-related revenue requirement associated with transmission assets under ISO operational control and subject to FERC's jurisdiction;

- Transmission Revenue Balancing Account Adjustment (TRBAA) is a FERC mechanism that ensures revenues received by PG&E from the ISO are credited to transmission rates for both retail and wholesale customers taking service from PG&E.

- Reliability Services Balancing Account (RSBA) is a FERC mechanism that ensures participating transmission owners properly recover from customers reliability services costs assessed by the ISO.

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7 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.

- End-Use Customer Refund Account (ECRBA) is a FERC mechanism that ensures that End-User customers receive accurate and timely refunds based on the difference between the as-filed and as-settled Transmission Owner Revenue Requirements.

- The Transmission Access Charge Balancing Account Adjustment (TACBAA) is a mechanism that ensures the difference between the 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.

6) Nuclear Decommissioning contributes less than 1 percent to PG&E's total authorized revenue requirement in 2016. Nuclear Decommissioning pays for the decommissioning/retirement of nuclear power plants.

7) Public Purpose Programs (PPP) contribute 8 percent to PG&E's total authorized revenue requirement in 2016. These revenue requirements include funding for energy efficiency programs, Electric Program Investment Charge, Statewide Marketing Education and Outreach, and the CARE discount. Natural gas revenue requirements are grouped into the following major categories: (1) Energy, (2) Distribution, (3) Backbone Transmission, (4) Local Transmission, (5) PPP, and (6) Storage. [8] Below is a description of each gas revenue requirement category:

1) Energy contributes about 21 percent to the total gas revenue requirement. These revenue requirements include:
    - Gas supply portfolio costs
    - Interstate capacity costs
    - Gas hedging

2) Distribution contributes about 59 percent to the total authorized gas revenue requirement. It includes the base distribution O&M costs and capital-related revenue requirements.[9]

3) Backbone Transmission contributes approximately 6 percent to the total gas revenue requirement and includes intrastate capacity costs. The Backbone Transmission System includes Lines 2, 300, 400 and 401, is used to transport gas from PG&E's interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution system.

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[8] The Distribution, Backbone Transmission and Local Transmission and Storage comprise the transportation rate component.

[9] The Gas Distribution revenue requirement reflects the CARE discount that is recovered through the CARE surcharge in the PPP rate component. Correspondingly, PPP revenue requirement reflects CARE discount revenue.

4) Local Transmission contributes approximately 5 percent to the total authorized gas revenue requirement. Local Transmission includes the pipelines used to accept gas from the backbone transmission system and transport it to the distribution system. Local transmission costs are included in end-use customer gas rates.

5) Storage contributes about 2 percent to 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.

6) Public Purpose Programs contribute 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. Description of Gas and Electric Rate Components

The revenue requirements discussed in the previous section directly align with PG&E's rate components. Generally, rate components are derived by dividing revenue requirements by sales. Therefore, changes in both revenue requirements and sales impact rates for gas and electric service. Rate pressures created by increasing revenue requirements are moderated when sales are also increasing. Adjustments in the allocation of revenue requirements across customer classes and rate tiers also impact the rates paid by individual customers. Table 4 below provides a summary of electric and gas revenue requirements.

Table 4: Summary of Revenue Requirements and Percentage of Total Revenue as of January 1, 2016

RATE COMPONENT	Electric Revenue Requirement $M	%	Gas Revenue Requirement $M(4)	%
Energy and Generation	$6,641	48%	$837	21%
Competition Transition Charge	410	3%	-	-
Distribution (1)	3,996	29%	2,334	59%
Energy Recovery Bonds and Department of Water Resource Bonds	410	3%	-	-
Gas Transmission / Backbone			236	6%
Electric Transmission	1,183	9%		
Local Transmission (Gas)	-	-	216	5%
Public Purpose Programs (2)	1,076	8%	246	6%
Nuclear Decommissioning	19	0%	-	-
Gas Storage	-	-	87	2%
Total Authorized Revenue Requirement(3)	$13,735	100%	$3,957	100%

(1) Includes 2016 CARE discount of approximately $510 million for electric.
(2) Includes 2016 CARE discount of approximately $112 million for gas which is collected in PPP rates.
(3) As of January 1, 2016. Values are approximated to the nearest million.
(4) The gas GHG revenue requirement and auction proceeds to be returned to customers will be implemented April 1, 2016, and are therefore is not reflected.

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, starting with the recession in 2009, and then continuing with the increases in distributed generation, and savings from energy efficiency, PG&E has had flat or declining sales. This results in fixed costs having to be 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's expansion is "intact," and Moody's projects the PG&E service territory will be an above-average performer in the long term. 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 decreased about 0.05 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 515 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 under 5,000 kWh per customer today. Only the growing number of customers has kept sales from falling more significantly.

Demand in some sectors is growing. Since the start of the current, prolonged drought in 2011, increased groundwater pumping by the drought-afflicted farm sector drove record agricultural sector electric sales. However, with a wet winter in progress, we expect agricultural sales to level off and begin to decline in 2016. Our industrial customers showed moderate sales gains in 2015, growing at approximately 2 percent over 2014, primarily due to improved economic conditions.

Overall, PG&E's electric sales decreased by 0.4 percent in 2015 over 2014, driven primarily by decreases in the residential and commercial sectors, offset by high agricultural sales due to persistent drought conditions. With continued growth in rooftop solar and a return to historical agricultural sales due to more normal rainfall conditions, the electric sales forecasts declines 1.1 percent in 2016.

B. Gas

Normally growth in core customers' use is mostly driven by increases in the number of customers. As the economy grows stronger in the PG&E service territory, natural gas demand would be expected to increase. However continuing efficiency improvements in the utilization of gas within the residential, commercial and industrial buildings will slow down that expected increase in gas demand.

In the past two years, California has experienced both warmer than normal winters and a continuation of a significant drought. These events have affected gas demand significantly in terms of less demand for space heating and lower demand for gas water heating. The combined effect of weather and continued energy efficiency and conservation has been a decrease in gas consumption of about 16 percent in 2014, and an increase of 2.5 percent in 2015 over prior year. A return to assumed normal temperatures and precipitation is expected to increase sales by about only 8 percent in 2016 due to the effects of continuing energy efficiency improvements.

In contrast to core customers, the demand for natural gas used in electric generation has been very high during the last three years, again driven by the drought that has lowered hydroelectric generation. Other factors such as new cleaner energy generation facilities and reductions in nuclear generating capacity have also contributed to this increase in demand by electric generation. Demand for natural gas use for electric generation is expected to decrease assuming normal weather conditions for hydroelectric generation and expected rate increases taking place through 2017.

Appendix: Outlook from May 1, 2016 to April 30, 2017.

See the table below for a listing of PG&E's pending proceedings affecting PG&E's 2016 and 2017 revenue requirements and new proceedings expected to be filed between now and April 30, 2017. 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 Implementation Date	Requested Amount ($ millions) Total Cost	2016 RRQ	2017 RRQ	Description	Affected Rate	Affected Rate Component
	Q1 2012									
1	Market Redesign and Technology Upgrade (MRTU) 2010 (re-filing)	A.12-01-014	January 31, 2012	January 1st of the year following CPUC Approval	21	N/A	65 (Incl. 2010 and 2012 RRQ)	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
	Q2 2012									
2	Market Redesign and Technology Upgrade 2011	A.12-04-009	April 16, 2012	January 1st of the year following CPUC Approval	15	N/A	8	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									
3	ERRA Compliance 2012 (incl. MRTU and Diablo Canyon Seismic Studies)	A.13-02-023	February 28, 2013	January 1st of the year following CPUC Approval	29	N/A	25.5 (incl. 2012 RRQ)	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,	Electric	Generation

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
								CPUC ordered PG&E to include review of incremental costs and cost recovery proposal of MRTU projects and Diablo Canyon Seismic Studies projects.		
	<u>Q4 2013</u>									
4	2015 Gas Transmission & Storage Rate Case	A.13-12-012	December 19, 2013	1/1/2015	4,560	1,347	1,518	The 2015GT&S rate case sets the rates, terms and conditions of service for PG&E's gas transmission (backbone and local transmission) and storage business for 2015-2017. Note: The CPUC has not issued a proposed decision however, these amounts will be adjusted to 1) amortize the 2015 RRQ in rates over 2016-2017 and 2) the $850M penalty to be funded by shareholders.as determined in a Phase II Decision.	Gas	Backbone Transmission; Local Transmission; Storage; Customer Access Charge (CAC)

* Amount is based on adopted funding. The amount to be requested has not been determined.
[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
	Q1 2014									
5	2013 ERRA Compliance Review (incl. MRTU, DCSSBA and RPS-related consulting fees)	A.14-02-008	February 28, 2014	1/1/2017	13	N/A	8	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
	Q4 2014									
6	2015-2017 Energy Savings Assistance Program and California Alternate Rates for Energy Application	A.14-11-010	November, 2014	1/1/2015		170	175	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; Gas	Electric PPP; Gas PPP

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
								Electric allocation: ESA52%-e/48%-g., CARE 80%-e/20%-g.		
	Q1 2015									
7	Electric Vehicle Infrastructure and Education Program	A.15-02-009	February 9, 2015	1/1/2017	87	5	16	Request for PG&E to build and own electric vehicle charging station infrastructure in PG&E's service territory.	Electric	Distribution
8	2014 ERRA Compliance Review (incl. DCSSBA and RPS-related consulting fees)	A.15-02-023	February 27, 2015	January 1st of the year following CPUC Approval	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
	Q2 2015									
9	CPIM 2014 Annual Report (Yr. 21)	N/A	May 21, 2015	Upon CPUC Approval	6	6		Compliance report for gas core procurement incentive mechanism for November 1, 2013 through October 31, 2014.	Gas	Procurement
10	Catastrophic Event	A.15-05-016	May 28, 2015	1/1/2017	27		27	The CEMA application requests recovery	Electric	Electric Distribution

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
	Memorandum Account (CEMA) 2015							of drought fire mitigation activities undertaken by PG&E's vegetation management department in response to Governor Brown's January 2014 Drought State of Emergency Proclamation and CPUC Resolution ESRB-4, in the amount of $26.6M.		
	Q4 2015									
11	2017 General Rate Case (GRC) Phase 1	A.15-09-001	September 1, 2015; Updated February 22, 2016	1/1/2017	8,249		8,249	Application to request approval of electric and gas distribution and utility-owned electric generation base revenues for the 2017 test year and the 2018-2019 attrition years. Incremental RRQ forecast in 2017 includes $71M for electric distribution, $199M for electric generation, and $63M for gas distribution.	Electric Gas	Electric Distribution Electric Generation Gas Distribution

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
12	Energy Storage Application	A.15-12-004	December 1, 2015	4/1/2018	4.7	N/A	N/A	The Storage Program has three primary goals of improving grid reliability, renewable integration, and reducing greenhouse gas emissions. Decision 13-10-040, requires each IOU to file a procurement application every two years, beginning on or before March 1, 2014, with proposals for energy storage procurement, use cases, or ownership scenarios, as well as proposed modifications based on previous procurement cycle experiences.	Electric	Electric Distribution
	Q1 2016									
13	2015 ERRA Compliance Review (incl. DCSSBA and RPS-related consulting fees)	TBD	February 29, 2016	January 1st of the year following CPUC Approval	6.8	N/A	6.8	Annual proceeding to review the utility-owned generation operations, economic dispatch of electric resources, utility retained generation fuel procurement, and entries	Electric	Generation

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
								to the ERRA and Diablo Canyon Seismic Studies balancing accounts for the 2015 record period.		
14	Solar PV Program Incentive Award	D.14-11-026	Q2 2016	1/1/2017	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	Demand Response 2017 Bridge Funding	R.13-09-011	February 2, 2016	1/1/2017	50.4	N/A	50.4	Per September 15, 2015 Joint ACR/ALJ ruling, PG&E will file demand response program proposals for 2017 bridge funding on February 1, 2016 electricity markets.	Electric	Distribution
16	Nuclear Decommission ing Cost Triennial Proceeding	TBD	March 1, 2016	1/1/2017	TBD	N/A	107*	The purpose of the NDCTP is to recover costs necessary to adequately fund the nuclear decommissioning trust funds for Diablo Canyon and Humboldt Bay Power Plant Unit 3 as well as to fund ongoing O&M costs associated with	Electric	Nuclear Decommissio n

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
								maintaining the current operational license of Humboldt Bay Power Plant Unit 3. PG&E will request a revenue requirement to fund these activities for the period 2017 through 2019.		
	Q2 2016									
17	CPIM 2015 Annual Report (Yr. 22)	N/A	May 16, 2016	Upon CPUC Approval	TBD	N/A	TBD	Compliance report for gas core procurement incentive mechanism for November 1, 2014 through October 31, 2015.	Gas	Procurement
18	ERRA 2017 Forecast	TBD	June 2016	1/1/2017	4,672 *	N/A	4,672*	An annual application that requests approval of PG&E's forecasted procurement related revenue requirement, including Energy Resource Recovery Account (ERRA) and non-bypassable charges – Ongoing Competition Transition Charge (CTC), Power Charge Indifference Amount (PCIA) and Cost Allocation Mechanism (CAM) non-bypassable	Electric	Generation; CTC; NSGC; PCIA GHG

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
								charges.		
19	Catastrophic Event Memorandum Account (CEMA) 2016	TBD	May 2016	January 1st of the year following CPUC Approval	TBD	N/A	TBD	The purpose of the CEMA is to recover incremental costs associated with repair and restoration of damaged PG&E facilities in association with declared disasters and complying with government orders associated with a declared disaster.	Electric Gas	Electric Distribution Electric Generation Gas Transmission and Distribution
	Q3 2016									
20	Transmission Owner 18	TBD	July 2016	3/1/2017	1,515 *	N/A	1,515*	Annual filing to recover transmission costs.	Electric	Transmission
21	2018 Gas Transmission & Storage Rate Case (2018 -2020)	TBD	TBD	1/1/2018	TBD	N/A	N/A[10]	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; Customer Access Charge

[10] The 2018 GT&S Rate Case will not impact rates until 2018.

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
										(CAC)
	Q4 2016									
22	Demand Response 2018 – 2020	TBD	November 2016	1/1/2018	58*	N/A	58*	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	Electric Distribution
25	2017 FERC Rate Filing for Annual Updates to the Transmission Balancing Accounts	TBD	October 2016	1/1/2017	TBD	N/A	(209)*	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	Electric	Electric Transmission

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
								Balancing 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. Similarly, the transmission access charge balancing account is filed in December for an effective date of March 1 of the following year		
26	2017 Public Purpose Programs Surcharge Rate Advice Letter	TBD	October 2016	1/1/2017	N.A	N/A	TBD	Annual filing consolidating approved gas public purpose programs, gas research and demonstration, and Board of Equalization administrative funding.	Gas	PPP
27	2017 Annual Gas True-Up (AGT) Advice Letter (Tier 2 Preview) and 2017 AGT Advice Letter (Tier 1 Final)	TBD	November 2016 and December 2016	1/1/2017	N/A	N/A	TBD	Annual filing consolidating gas transportation rate changes authorized by the CPUC and true-up of balancing account balances. This filing is supplemented in December.	Gas	Distribution; Backbone Transmission ; Local Transmission ; Gas Storage; CAC; PPP Surcharge

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined

Line No.	Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Amount ($ millions)			Description	Affected Rate	Affected Rate Component
					Total Cost	2016 RRQ	2017 RRQ			
28	2017 AET Advice Letter and Supplemental Advice Letter filing	TBD	September 2016 and December 2016	1/1/2017	N/A	N/A	TBD	Annual filing to adjust for balancing account over/under collections, and consolidation of electric revenue requirements adopted by the CPUC. This filing is supplemental in December.	Electric	CTC; Distribution; DWR; ECRA; Generation; NSGC; ND; PPP; PCIA; Transmission
29	Transmission Access Charge Balancing Account Adjustment (TACBAA)	FERC Docket No. TBD	December 2016	3/1/2017	TBD	N/A	251*	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

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[N/A] – No RRQ or Rate Impact
[TBD] – To Be Determined