BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation

Application 17-06-005
(Filed June 1, 2017)

OPENING BRIEF OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY, SILICON VALLEY CLEAN ENERGY, AND SONOMA CLEAN POWER AUTHORITY IN PG&E’S ENERGY RESOURCE RECOVERY ACCOUNT APPLICATION

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OPENING BRIEF OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY, SILICON VALLEY CLEAN ENERGY, AND SONOMA CLEAN POWER AUTHORITY IN TO PG&E’S ENERGY RESOURCE RECOVERY ACCOUNT APPLICATION

I. Introduction


The application is subject to two undisputed statutory requirements under Public Utilities Code § 451: (1) any rate proposed by PG&E must be “just and reasonable”; and (2) PG&E may not “change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before
the commission and a finding by the commission that the new rate is justified.” Given these requirements, PG&E’s application for an increase in the Power Charge Indifference Adjustment (“PCIA”) should be rejected. PG&E has not submitted evidence sufficient to carry its burden to show that the proposed PCIA is “fair and reasonable” or “justified.”

We focus on three defects in PG&E’s Application: (1) the general lack of evidentiary support for the requested PCIA; (2) the improper inclusion of fuel costs that solely benefit bundled customers; and (3) the erroneous reliance on stale, unauthenticated data (derived from a now non-existent website) to calculate the “Green Adder” portion of the Market Price Benchmark (“MPB”).

II. Insufficient Evidence Showing Justification for Requested PCIA

The magnitude of PG&E’s request ($583,453,557 or over one-half billion dollars) demands cautious and careful consideration under the applicable standards of proof. While the Commission has recently tended to treat the utility’s burden of proof in a ratesetting proceeding under the preponderance of the evidence standard,¹

¹ See, e.g., D.13-11-005 at 8 (SCE’s ERRA Compliance and Reasonableness Review, adopting the preponderance standard); D.14-07-006 at 6 (SDG&E’s ERRA Costs and Related Matters, adopting the preponderance standard); D.15-07-044 at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting, but noting that the preponderance of evidence is the “default standard to be used unless a more stringent burden is specified by statute or the Courts.”); but see D.00-02-046 (suggesting that the clear and convincing standard is appropriate across differing types of ratesetting proceedings).
the Commission retains significant discretion in applying its chosen standard to the circumstances at hand. PG&E, as the applicant, has the burden of affirmatively establishing the reasonableness of all aspects of its application. The Commission has previously described the preponderance of evidence standard in “terms of probability of truth, e.g., ‘such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth’.”

Given the magnitude of this figure and public policy issues at stake, it is reasonable for the Commission to apply this standard vigorously to require PG&E to prove up – to “justify”, using the statutory term – both that overall revenue figure and the individual rate-class PCIA rates it is requesting for 2018 in clear, accurate, specific, and transparent way. A review of the written testimony and workpapers supporting the PCIA request, when combined with the testimony of PG&E’s witness Donna Barry at the hearing, and the written and oral testimon of all witnesses, shows PG&E has failed to meet its burden, by a preponderance of the evidence, to demonstrate that its request will result in just and reasonable rates according to § 451.

The PCIA differs from most rates (such as PG&E’s bundled generation rate), in that the “revenue requirement” used to calculate PCIA rates is not an actual “real” number. Rather, the revenue requirement is itself a “derived” or calculated figure.

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2 D.12-12-030 at 40.
3 Id. (citing D.08-12-058).
based on forecasts rather than actual costs. As noted in Ms. Barry’s testimony at the hearing, she does not develop the PCIA revenue requirement reflected in Table 9-1 of her written testimony; rather, that figure is calculated by the PG&E rates department, as are the individual PCIA rates for various customer classes and vintages. Although Ms. Barry testified that the “rates department” created a “rate model” and generated workpapers explaining how individual rate-class and vintage PCIA rates were calculated, the path from the “above-market cost” figures in Line 15 of her Table 9-4 to the final PCIA rates for different rate classes in each vintage is completely opaque.

Ms. Barry’s testimony during hearings describes a disjointed process to derive the PCIA, where different personnel within PG&E work separately from each other in disconnected silos. Ms. Barry, for example, calculates the PCIA revenue requirement by vintage, but the amount of the forecasted 2018 PCIA revenue requirement and the allocation of it among the various customer classes, *i.e.*, the creation of the actual PCIA rate for each vintage, is done by the rates department. Neither has the context the other is working from, and neither can explain the details of what the other does. The result, whether intentional on PG&E’s behalf or not, is a half-billion dollar charge the derivation of which no one person at PG&E is able to walk through and explain to

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4 Transcript of Evidentiary Hearing, 41:7-11, 47:5-10.
5 Transcript, 44:27 – 46:3.
the Commission and parties through testimony on the record. PG&E’s failure to present its evidence with either clarity or convincing force, ultimately, causes it to fail its burden and frustrates the Commission’s duty to make a finding supported by substantial evidence.

PG&E’s disjointed process to derive the PCIA also suffers from a “chicken or egg” problem: i.e., Which comes first, the revenue requirement or the PCIA rates? This “which came first” problem is apparent when Ms. Barry’s written testimony (PG&E Opening Testimony at 9-5) is compared to Mr. Bremault’s testimony in Chapter 14 (PG&E Opening Testimony at 14-4). Ms. Barry says (emphasis added):

PG&E calculates the vintaged PCIA revenue requirement for non-exempt departing customers by utilizing the vintaged PCIA rates which are developed based on system-level power charge indifference revenue requirements shown on Table 9-4, line 12. Specifically, the vintaged PCIA rates are multiplied by the non-exempt [Departing Load] to generate a forecast for the PCIA revenue requirements. The PCIA revenue requirements are positive and reflect a cost of $583.5 million to non-exempt departing customers that depart bundled service between 2009 and 2018. This positive PCIA revenue requirement will be a credit to bundled customers in ERRA.

Mr. Bremault says (emphasis added):

The rate design approved for the non-DWR cost portion of the indifference calculation was a top 100-hour rate design, which was originally approved in D.02-11-022 and is the same rate design approved for ongoing CTC. The PCIA rate for each vintage year is developed by utilizing the same proportional top 100 allocation factors used to develop ongoing CTC rates (shown in Table 14-2). For each vintage year, the ratio of the PCIA revenue requirement (Chapter 9, Tables 9-3 and 9-5) to the ongoing CTC revenue requirement is multiplied by the ongoing CTC rates to
determine the PCIA rates. In all cases, the final PCIA rates include franchise fees for the California Department of Water Resources bond charge.

The problem is clear – Ms. Barry says that PCIA rates are multiplied by expected departed load sales to generate the PCIA revenue requirement; Mr. Bremault says the PCIA revenue requirement is used to develop PCIA rates. Both cannot be right—this is circular reasoning. While perhaps this discrepancy arises due to differences between the two PG&E witnesses as to the meaning of “revenue requirement,” the passages demonstrate the opacity and confusion surrounding PG&E’s calculation of the PCIA.9

This opacity is not only problematic, it overcomes PG&E’s ability to carry its burden on the issue and makes its request deficient a matter of law. It is impossible to derive vintage-by-vintage PCIA calculations for 2018 without making an estimate of vintage-by-vintage departed load sales in 2018. PG&E, thus, does not provide the necessary evidence when it provides only sales by individual CCAs and for direct

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8 In fact, neither table referred to by Mr. Bremault contains a “PCIA revenue requirement.” Table 9-3 is the CTC revenue requirement calculation, and Table 9-5 is the Market Price Benchmark calculation. And assuming Mr. Bremault meant to refer to Table 9-4, neither Line 12 nor Line 15 represents a “revenue requirement” – rather, they represent the above-market cost of PG&E’s generation portfolio for the particular vintages. See PG&E Opening Testimony at 9-4, line 15 (using the term “indifference amount”).

9 Although Ms. Barry said she would provide a reference to where in the workpapers the rate department’s calculations of the PCIA rates occur, Joint CCA Parties have not received such a reference.
access customers as a whole, with no direct distinction by vintage within those categories (McCann Testimony, 13: Footnote 25.) This is yet another critical piece of evidence that does not appear in PG&E’s original testimony and workpapers.

As the foregoing makes clear, PG&E has not provided sufficient evidentiary support to justify its proposed 2018 Rates through the testimony and workpapers it has submitted to the Commission, as required by § 451. PG&E’s proposed PCIA rates for 2018 should not be approved unless and until it provides such a justification through clear, understandable analysis – i.e evidence, specifically linking the “above-market” costs for each vintage as shown on Table 9-4 in PG&E’s Testimony to the specific PCIA rates proposed to be assessed against departed customers in each vintage.

III. Fuel and other Variable Costs of Dispatchable Generation Facilities Should be Excluded from the PCIA

PG&E includes in the PCIA the cost of fuel and other variable costs incurred by PG&E to generate power used solely to serve its bundled customers or used to generate excess revenues from sales into the CAISO. These fuel and variable costs should not be included in the PCIA because: (1) when incurred to meet PG&E

11 See Testimony of Richard McCann, 3:5-9; PG&E Opening Testimony at 3-7:12-14; Transcript, 23:6-12. PG&E does not dispute that such costs are included in the PCIA rates requested by PG&E in its application.
bundled customer demand, such costs are “load based” and subject to exclusion under the rationale of Commission Decision 11-12-018; and (2) when incurred for the purposes of maximizing revenues from sales to the CAISO, such costs are “avoidable” and thus not subject to recovery from departed CCA customers under Public Utilities Code §366.2(f)(2).

It is legal error to include these costs in the PCIA since “avoidable” costs are expressly excluded from the PCIA by law. Specifically, § 366.2(f)(2) limits the inclusion of costs in the PCIA to those that are “net unavoidable electricity purchase contract costs attributable to the [departing] customer, as determined by the commission.” Decision 11-12-018 sets a standard for excluding a cost from the PCIA if it “varies directly with the load served.”\(^\text{12}\) In that case, the Commission addressed “CAISO load-based costs” that had been included in the PCIA despite the fact that “the IOUs avoid load-related CAISO charges when load departs.”\(^\text{13}\) The Commission concluded that such costs should be excluded from the PCIA because the methodology at the time “inappropriately [treated] CAISO costs as if they are

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\(^{12}\) D.11-12-018, p. 32.  
\(^{13}\) Id. at 30, 32 (adopting App. A to Exh. 100 as “constituting the pertinent charges to be excluded from the total portfolio and [Market Price Benchmark] calculation.”). “These costs include various charges for grid management services, ancillary services, congestion, unaccounted for energy, neutrality and other load-based fees.” R.07-05-025, Exh. 100, 32:17-19 (summarizing the contents of App. A).
unavoidable, above-market utility generation-related costs.” 14

The Commission allows for “fuel costs” to be included in the PCIA, and the Joint CCA Parties are not advocating in this docket that the current PCIA methodology be changed. However, the Commission has never specified which fuel costs be included in the current methodology, and those that are avoidable and vary directly with the load being served by an IOU must be excluded as contrary to §366.2(f)(2).

The testimony of PG&E’s witness Donna Barry at the evidentiary hearing provides perhaps the best rationale for why such fuel and variable costs should not be included in the 2018 PCIA calculation:

Q [By Mr. Shupe] And the costs of your spot market purchases that you were talking about where you are just buying power from the ISO and you are not generating at the same time, are those costs put into line 3 of table 9.4?

A No. Spot market purchases are not.

Q And why is that?

A The idea is that the spot market is used to serve bundled load, spot market purchases. It’s not stranded cost associated with long term contracts. It’s -- it is power purchased to serve bundled load.

Q And you used the term, stranded costs?

A I did.

14 Id. at 31, 109 (Conclusion of Law 14).
Q Yes. Can you tell me what you understand by the term stranded costs?

A It was a term that was used originally in the 04-12-048 decision that established the concept for these nonbypassable charges. *But basically, I think it’s looking at long-term resources that would have potentially above market cost, meaning they were required to purchase the generation and the amount of revenues we might receive from the market are less than the cost of the resource. And so the costs above market I think people have referred to as stranded costs.*

(Transcript, 19:8 – 20:8, emphasis added). There is no principled difference between fuel and variable costs incurred by PG&E to serve its bundled load (which PG&E has included in the PCIA calculation) and the spot-market CAISO costs incurred by PG&E to serve its bundled load (which are excluded from the PCIA calculation). Neither involves a “stranded cost associated with a long-term contract.” Neither involves generation that PG&E was “required to purchase” (or create) before Joint CCA Parties’ customers departed. Like the load-based CAISO costs disallowed in D.11-12-018, these load-based costs should also be excluded from the PCIA.

PG&E’s arguments against exclusion of these costs either miss the point or, as discussed below, actually support exclusion.

First, PG&E points to Commission decisions that have expressly said that fuel costs can be included in the PCIA. (PG&E Rebuttal Testimony at 1-7.) But the Joint CCA Parties are not contending that all fuel costs should be excluded. For example, fuel costs for PG&E’s Diablo Canyon nuclear facility, which supplies “baseload” capacity that cannot be ramped up or down in response to changes in load levels or
corresponding wholesale prices, are properly included in the PCIA. None of the Commission decisions cited by PG&E say that all PG&E fuel and variable generation costs are automatically eligible for inclusion in the PCIA.\textsuperscript{15}

PG&E next argues that it does not use its generation assets to serve its own bundled customer load. (PG&E Rebuttal Testimony at 1-9 to 1-10.) This surprising assertion is contradicted by other PG&E testimony (PG&E Opening Testimony at 2-1:23-28, emphasis added):

This section describes the development of sales and peak demand forecasts for PG&E’s service area. PG&E develops its resource mix, as well as a reserve margin, to serve this load. The electric sales forecast for PG&E’s bundled electric customers is a key input to the procurement cost modeling described in subsequent chapters and used in the calculation of the rates discussed in detail in Chapter 14.

Although Joint CCA Parties have not evaluated the “PPP” model used by PG&E to forecast generation from its portfolio for 2018 because PG&E says it is confidential, and refused to provide it, there is little doubt that serving bundled customer load is the driving factor in the operation of the (mostly) fossil-fuel fired generation resources at issue. To the extent that these facilities incur fuel and variable costs solely to meet this bundled load, those costs should be excluded from the PCIA. As noted above, PG&E

\textsuperscript{15} Nor could that be the rule. If, for example, PG&E were to incur engage in an uneconomic dispatch of a fossil fuel facility, even PG&E would concede that the fuel costs related to that uneconomic dispatch should be excluded from PCIA costs. As discussed below, the measure of “economic” differs greatly between bundled and unbundled customers.
bears the burden of clearly demonstrating that the costs it seeks to recover are proper, and it has failed to do this.

Finally, PG&E submitted rebuttal testimony making the claim that departed customers who pay the PCIA are better off when PG&E incurs (and charges departed customers for) fuel and variable costs. In her written rebuttal testimony, Ms. Barry stated:

Since dispatchable resources are selected to dispatch when their marginal operating costs are less than the market price of power in that hour, by definition, those resources only incur incremental operating costs when they are “in the money,” regardless of the demands of bundled customers in the period where the resources are dispatched. In short, the CAISO does not dispatch resources to meet the load of a specific LSE.

Under the total portfolio indifference calculation, the resulting market revenues help to offset the fixed costs of the generating resource. Thus, “in the money” sales of energy into the CAISO market help generate revenues to reduce the PCIA and lower the generation-related costs that would otherwise be allocated to SCP and other LSEs under the PCIA.

(PG&E Rebuttal Testimony at 1-10:16-26.)

However, Ms. Barry’s testimony at the evidentiary hearing contradicted these statements. Although Ms. Barry first testified that revenues received by PG&E from the CAISO for power delivered to the grid were netted out from the “Total Portfolio Cost” figures on Line 3 of Table 9-4 (Transcript at 15:7-21), she later stated that was not the case:
Q [By Mr. Shupe] I'm sorry. I want to ask you again about this question of crediting CAISO revenues and whether or not that actually feeds into the figure that's on line 3 of table 9.4. And the reason I'm a little bit confused is as I understand it, the way the PCIA gets calculated is you take that total portfolio cost and then you apply what's called the Market Price Benchmark to it to calculate what you call the above market costs, right?

A That's correct.

Q And --

A I will clarify, though, that the benchmark credit is not on line 3. It is on line 5.

…

Q The total portfolio cost is on line 3. And what you call the market value, which as I understand it is what you get when you multiply the Market Price Benchmark times the amount of generation that's shown on line 1?

A That's correct.

Q Okay. And then you subtract those two and you get above market – essentially above-market costs which are shown on line 6, correct?

A Correct.

Q The Market Price Benchmark itself has a component that's called the brown power component.

A Sure.

Q Right? And that is supposed to represent, as I understand it, the – what you would get basically from just selling non-renewable power on to the CAISO
grid next year 2018, correct?

A    Yes. It's a proxy for --

Q    It's a proxy for that. So my question is, if you are already netting out your revenues from CAISO in line 3, why isn't that a double -- why I'm confused is that seems to me that like it's a double counting.

A    That's why I want to try and clarify. Line 3 does not net the ISO revenues. That netting of ISO revenues happens in our spot market purchase line. So again, the netting of the ISO generation revenues received from the market is netted against the costs we receive from ISO to serve our load. The net of those two equals the spot market purchase line item. Spot market purchases are not part of this calculation.

Transcript at 24:1 – 26:4 (emphasis added). Thus, when PG&E incurs fuel and variable costs to run dispatchable facilities, those fuel and variable costs are added into the PCIA, but the revenues received by PG&E are only netted against the costs of power taken from CAISO grid to serve its bundled customers. This testimony again demonstrates that such costs are, in fact, load-related costs that should be excluded from the PCIA.16

16 Note that this testimony also casts doubt on Ms. Barry’s testimony that there was no way in which the method by which PG&E dispatches its generation into CAISO that could benefit bundled customers at the expense of departed load customers (Transcript at 22:15-21). PG&E will operate a dispatchable facility (and thus incur fuel and variable operating costs) whenever the CAISO market price is greater than those costs. (Testimony at 3-7:12-14; Rebuttal Testimony at 1-10:10-15.) But while bundled customers receive a benefit from that generation equal to the CAISO market price, Ms. Barry testified at the evidentiary hearing that the benefit to unbundled departed customers is limited to the “brown power” portion of Market Price Benchmark.
PG&E also contends that if fuel and variable costs are excluded from the PCIA calculation, then all generation estimated for 2018 from PG&E dispatchable resources must also be excluded from the PCIA calculation, which in turn would result in a higher PCIA calculation. (Rebuttal Testimony at 1-11:3 – 1-12:10 and Table 1-1.) PG&E’s argument is incorrect for two reasons.

First, Ms. Barry testified at the evidentiary hearing that after excluding the specific generation facilities, she did not ask for the “PPP” dispatch model to be rerun to see what PG&E’s 2018 generation portfolio would look like without these facilities. (Transcript at 38:12-26.) Without running the PPP model again, there is no way to know what PG&E’s 2018 generation mix would be, and thus no basis for any estimate of an “alternative” PCIA. Ms. Barry’s written Rebuttal Testimony on this point completely lacks foundation and must not be given any weight.

More importantly, however, PG&E misunderstands the fundamental basis for the Joint CCA Parties’ argument for excluding fuel and variable costs only. The Joint

(Transcript at 29:18 – 31:4.) While in fact departed load customers receive a benefit or “credit” for generation equal to the entire Market Price Benchmark (Testimony at 9-4:8-14), this still creates a system in which PG&E can operate its dispatchable resources to the benefit of bundled customers and the detriment of departed customers. For example, assuming fuel and variable costs equaled $60 per MWh, PG&E would run its facility if the market price were $65 per MWh. Its bundled customers would receive a $5 per MWh benefit, while departed customers would incur an additional cost of approximately $5 (the fuel/variable costs minus the Market Price Benchmark), which would be recovered in the PCIA. This problem disappears if fuel and variable costs are excluded altogether from the PCIA, which, as noted, is appropriate given that they are “load based” and not “stranded” costs.
CCA Parties are not saying that PG&E may not, or should not, run these dispatchable facilities at all. Indeed, for the reasons noted in PG&E’s Testimony, Rebuttal Testimony, and testimony at the hearing, running the facilities may well benefit bundled customers by reducing their overall costs. Rather, the basis for excluding fuel and variable costs is that they are load-based (they relate solely to bundled customers) and they are not “stranded” (they are not costs that PG&E incurred on behalf of departed customers, or must continue to incur after the customers’ departure).

PG&E’s argument ignores the fact that even if the fuel and variable costs are excluded from the PCIA, departed load customers will continue to pay as a part of the PCIA ongoing fixed costs relating to dispatchable facilities. The Joint CCA Parties are not contending in this proceeding that the capital and fixed costs for these resources should not be included in the PCIA under the current interpretation of the rules. Because departed customers are still paying a part of the overall cost of such facilities, generation from those facilities should be included in the overall PG&E “Portfolio Generation” figures shown on Table 9-4 of PG&E’s Testimony.17

17 In addition, no Commission decision relating to the PCIA or any of its successors says that PG&E may exclude from Lines 1 and 2 of Table 9-4 generation as to which departed customers do not pay their share of 100% of the costs. Indeed, the basis in Commission decisions upon which PG&E excludes any generation from the PCIA calculation for different vintages is unclear. The “vintaging” process was designed to keep departed customers from paying for generation resource costs that were not incurred on their behalf. PG&E’s exclusion of the amount of generation from those resources (shown as diminishing generation values on Lines 1 and 2 of Table 9-4 as
Commission Decision 11-12-018, discussed above, makes clear that some costs relating to a specific facility may be included in the PCIA, while other costs are excluded. That decision disallowed CAISO load-based costs from being included in the total portfolio cost figure from which the PCIA was calculated (i.e., from Line 3 on Table 9-4). But nothing in that decision suggested that this disallowance of costs should result in the exclusion of any generation (i.e., a reduction in Line 1 of Table 9-4). This is consistent with Joint CCA Parties’ position, as well as the manner in which the load-based, non-stranded fuel and variable costs were excluded from the PCIA calculation in the Testimony of Richard McCann.

PG&E did not dispute the specific dollar amount of fuel and variable costs that Dr. McCann identified as being load-based and avoidable. As noted in Dr. McCann’s testimony, the total amount of these costs is $238.4 million dollars. (McCann Testimony at 10:18-19.) This amount should be excluded from the “Total Portfolio Cost” figures for each vintage (Line 3 of Table 9-4), which results in a decrease in the “PCIA RRQ” shown on Line 15 of Table 9-4 in the range of 11% to 13%.

IV. The “Green Adder” Component of the Market Price Benchmark Relies on a Fictitious Website Link and Should Be Corrected

vintages go back in time) is inconsistent with the Commission’s direction that the PCIA be calculated based on the market value of PG&E’s entire portfolio. By reducing the amount of generation on Lines 1 and 2 for earlier vintages, PG&E’s calculation results in a lower-than-actual “market value” for those vintages, and thus a higher-than-justified PCIA.
The Commission should give no weight to PG&E’s proffered evidence on the “DOE Adder” portion of the “Green Adder”, as such evidence has not properly been presented in this case. Dr. McCann’s testimony shows that the publicly available source for the Department of Energy database purportedly used by PG&E to calculate the “DOE Adder” portion of the “Green Adder” does not actually exist.18

While it may be appropriate for the Commission to take judicial notice of data or statistics housed on a website—particularly where the source of the website is reasonably reliable and trustworthy19—it is wholly inappropriate for the Commission to take judicial notice of data on a website that no longer exists. Moreover, it is important to note here that the Commission originally recognized the limitations of relying on the DOE source of data in D. 11-12-018 and directed that it only be used

18 The problem with the DOE data can be most easily be seen by simply clicking on the web address cited by the advice letter as the source for the data. Contrary to the representation made in the advice letter, that address: (http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1) does not lead to a database of “State-Specific Utility Green Pricing Programs.” Rather, that address redirects to an entirely different page, which nowhere contains any links to or information about the alleged database. A visit to a publicly available web-archive website (https://web.archive.org/) reveals that the last screen shot of this page recorded was January 25, 2017, shortly after the last Presidential inauguration and around the time widespread changes were made to executive agency websites by the new administration.

19 See, e.g., Matthews v. Nat’l Football League Mgmt. Council (9th Cir. 2012) 688 F.3d 1107 (taking judicial notice of a professional football player’s statistics on the National Football League’s website, noting that Fed. R. Evid. 201(b)(2) “allow[s] a court to take judicial notice of a fact “not subject to reasonable dispute because it... can be accurately and readily determined from sources whose accuracy cannot be reasonably questioned.”).
until better sources become available.\textsuperscript{20} Thus, when the DOE website is no longer available, it is no longer possible for PG&E to comply with the directive to provide the most recent 12-month data from that website. It would have been prudent for PG&E to alert the Commission to that deficiency (the unavailability of recent DOE data) in its application filing. Instead, the attachment included in Appendix A to PG&E Advice Letter 4927-E—included by reference in the application—indicates that the data relied upon in this application was “last updated January 2015.” PG&E’s failure to alert the Commission to the unavailability of this data, and to mitigate the loss of the required data source by providing supplemental, relevant data in its filing, does not justify Commission reliance on stale data that can no longer be verified as consistent with the original DOE source.\textsuperscript{21}

Further, Dr. McCann’s testimony calls into question whether the data used by PG&E even originated with the Department of Energy in the first instance. (McCann Testimony, 11:13-20.) Dr. McCann’s testimony demonstrates that the information in the database used by PG&E is in many cases out of date and inaccurate. (McCann Testimony, 12:1 – 13:12.) Given the inability to confirm the origin of the data used by

\textsuperscript{20} D.11-12-018 at 23.

\textsuperscript{21} The Joint CCA Parties acknowledge that secondary evidence may be appropriate in some circumstances, but oppose reliance on PG&E’s account of the contents of the DOE data when the original source is no longer available in the manner contemplated by D.11-12-018 (i.e., a transparent, publicly-available data source) and cannot be independently vetted or examined.
PG&E, plus the inaccuracies in the data shown by Dr. McCann, the Joint CCA Parties contend that the “DOE Adder” must be given no weight in this context and the more accurate and verifiable “URG Green” figure be used as the “Green Adder” for purposes of setting the Market Price Benchmark.

Ignoring or giving no weight to the DOE data is justified under the circumstances present here and is well within the range of discretion the Commission reserved for itself in D. 11-12-018 when considering the prospective validity and value of DOE data sources for this purpose. As the Commission observed in D.11-12-018:

We recognize that questions and concerns have been raised regarding the usefulness of the DOE data sources as representative of the California market. We conclude, however, these concerns go to the weight that should be accorded to the DOE data sources.

In light of the fact that the Commission’s identified source of data no longer exists, and that the data presented is nearly three years old, the Commission should give no weight to the data proffered as DOE data in this case.

In its Rebuttal Testimony, however, PG&E claims that the Commission has already approved the accuracy of the DOE database through its approval of Advice Letter No. 4927-E (PG&E Rebuttal Testimony at 1-12:18-21, providing a link to the advice letter at https://www.pge.com/tariffs/tm2/pdf/ELEC_4927-E.pdf). However, a

22 D.11-12-018 at 23.
23 Id.
plain reading of AL 4927-E shows this is incorrect. AL 4927-E by its terms says that it is intended to provide “data necessary to calculate the market price benchmark (MPB) for 2017.”

It is simply inaccurate to claim or imply that the Commission has approved the DOE data for use in the 2018 ERRA forecast. As stated above, the Commission is incapable of taking judicial notice of data from a website that no longer exists, and reliance on stale data is inconsistent with the directive in D. 11-12-018 and Resolution E-4475 that data used be from the most recent 12-month period.

The Commission should not calculate the Market Price Benchmark based upon a database that simply does not exist – particularly when the last available version of that database is full of errors, as Dr. McCann’s testimony lays out in detail. Given the lack of data, the “Green Adder” should be calculated based solely on actual in-state IOU renewable energy contracts, as shown in the “IOU RPS Premium” line (Line 18) of Table 9-5 of PG&E’s Testimony. This would result in a change to the “Market Price Benchmark” for each vintage as shown in Revised Table 9-4 in Attachment D of Dr. McCann’s Testimony.

V. Conclusion

24 PG&E AL 4927-E at 1 (emphasis added).
25 Resolution E-4475 at 4 (citing the directive of D.11-12-018 that each utility file an advice letter providing the most recent 12 month figures derived from the DOE survey of Western US renewable energy premiums.)
PG&E has failed to meet its burden of showing that the PCIA rates requested for 2018 are “just and reasonable.” PG&E has failed to meet its burden of showing that its requested 2018 rates are “justified.” The evidence presented to the Commission through written and oral testimony is insufficient to allow the Commission to determine whether or not the requested rates were properly calculated. In addition, fuel and variable costs relating to PG&E’s dispatchable generation facilities should be excluded from the “Total Portfolio Cost” upon which the PCIA is based, and the Market Price Benchmark should be revised as discussed in Section IV above. The Commission should require PG&E to meet and confer with Joint CCA Parties and develop recalculations of each PCIA rate accounting for such changes.

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Respectfully submitted,

/s/
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