

GOVERNMENT OF PUERTO RICO  
PUBLIC SERVICE REGULATORY BOARD  
PUERTO RICO ENERGY BUREAU

IN RE: PUERTO RICO ELECTRIC  
POWER AUTHORITY RATE REVIEW

CASE NO.: NEPR-AP-2023-003

SUBJECT: Guidance for Phase 2 Rate  
Review Filing and Scheduling of Technical  
Conference

NEPR

Received:

Feb 17, 2026

5:03 PM

INITIAL BRIEF ON RATE DESIGN OF  
OFFICIAL COMMITTEE OF UNSECURED CREDITORS OF PREPA

**TABLE OF CONTENTS**

|                                                                                                                                                   | <b>Page</b> |
|---------------------------------------------------------------------------------------------------------------------------------------------------|-------------|
| I. COMMITTEE’S INTEREST IN THIS RATE CASE: LEGACY DEBT RIDER.....                                                                                 | 2           |
| II. ANY LEGACY DEBT RIDER IS PREMATURE AND LACKS NECESSARY EVIDENTIARY FOUNDATION .....                                                           | 3           |
| A.    Facially Incorrect Filings on PREPA’s Legacy Debt Can Provide No Foundation for a Legacy Debt Rider .....                                   | 4           |
| B.    Waiting to Implement Any Legacy Debt Rider Is Also Consistent with Relevant Precedent.....                                                  | 7           |
| a.        Entergy New Orleans.....                                                                                                                | 7           |
| b.        PG&E.....                                                                                                                               | 8           |
| C.    Both Experts That Advocate for Legacy Debt Rider Offer No Reliable Evidence of Amount, Format, or Structure.....                            | 9           |
| 1.        Mr. Sam Shannon.....                                                                                                                    | 10          |
| 2.        Dr. Susan Tierney .....                                                                                                                 | 11          |
| a.        Dr. Tierney Offers No Support for Any Amount, Form, or Structure of a Legacy Debt Rider .....                                           | 11          |
| b.        Dr. Tierney Is Under-Informed, and Outright Mistaken, About PREPA’s Current and Historical Riders .....                                 | 13          |
| c.        Dr. Tierney Erroneously Limited Her Analysis Exclusively to the Bondholders, Thus Ignoring the Total Amount of PREPA’s Legacy Debt..... | 15          |
| d.        Dr. Tierney Undertook No Search for Similar Situations in Past Utility Bankruptcies to Support Her Conclusions.....                     | 16          |
| e.        The Two “Examples” Relied on by Dr. Tierney Have No Similarities to PREPA, or PREPA’s Title III Case.....                               | 17          |
| f.        Dr. Tierney’s Touted Benefits of Premature Implementation of a “Placeholder” Rider Are Speculative and Unquantifiable.....              | 20          |
| III. AWAITING THE OUTCOME OF PREPA’S TITLE III CASE IS THE ONLY RATIONAL OUTCOME—CONSISTENT WITH THE “JUST AND REASONABLE” STANDARD.....          | 22          |
| IV. CONCLUSION.....                                                                                                                               | 25          |

## TABLE OF AUTHORITIES

|                                                                                                                                                                                                                                                                                                                                  | Page(s)    |
|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------|
| <b>Cases</b>                                                                                                                                                                                                                                                                                                                     |            |
| <i>Consejo de Titulares del Condominio Atl. v. Mapfre Praico Ins. Co.</i> ,<br>KLAN202000468, 2020 PR App. LEXIS 1436 (Aug. 31, 2020).....                                                                                                                                                                                       | 4          |
| <i>De León v. Keleher</i> ,<br>KLCE201800796, 2018 PR App. LEXIS 2043 (June 27, 2018).....                                                                                                                                                                                                                                       | 4          |
| <i>In re Entergy New Orleans, Inc.</i> ,<br>Case No. 05-17697, ECF No. 1676 (Bankr. E.D. La. Feb. 5, 2007) .....                                                                                                                                                                                                                 | 7          |
| <i>In re Entergy New Orleans, Inc.</i> ,<br>Case No. 05-17697, ECF No. 1989 (Bankr. E.D. La. May 7, 2007) .....                                                                                                                                                                                                                  | 8          |
| <i>In re Fin. Oversight &amp; Mgmt. Bd. for P.R.</i> ,<br>121 F.4th 280 (1st Cir. 2024).....                                                                                                                                                                                                                                     | 5          |
| <i>Maldonado Pagán v. Departamento de Corrección y Rehabilitación</i> ,<br>KLRA202100183, 2021 PR App. LEXIS 1085 (Apr. 27, 2021).....                                                                                                                                                                                           | 4          |
| <i>Rebollo v. Yiyi Motors</i> ,<br>161 DPR 69 (2004).....                                                                                                                                                                                                                                                                        | 4          |
| <b>Statutes &amp; Legislation</b>                                                                                                                                                                                                                                                                                                |            |
| 22 L.P.R.A. § 1054x(a)-(b).....                                                                                                                                                                                                                                                                                                  | 4          |
| 22 L.P.R.A. § 1054x(c).....                                                                                                                                                                                                                                                                                                      | 23         |
| Act 17-2019 Puerto Rico Energy Public Policy Act.....                                                                                                                                                                                                                                                                            | 14         |
| Act 57-2014 Puerto Rico Energy Transformation and RELIEF Act.....                                                                                                                                                                                                                                                                | 14, 22, 23 |
| Ca. AB 1054 § 1(a)(3) (2019-2020) .....                                                                                                                                                                                                                                                                                          | 19         |
| <b>Regulatory &amp; Other Authorities</b>                                                                                                                                                                                                                                                                                        |            |
| Commonwealth of Massachusetts, Session Laws Chapter 164, <i>An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein</i> , § 1B(B) (1997).....                                        | 19         |
| California Public Utilities Commission, <i>Decision Approving Imposition of a Non-Bypassable Charge to Support California's Wildfire Fund and Adopting Rate Agreement Between The California Department of Water Resources and the California Public Utilities Commis[sion]</i> , Rule No. 19-07-017, at 6 (Oct. 24, 2019) ..... | 17, 19     |
| Hempling, Scott, <i>Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction</i> , Ch. 1.B.4. P. 4. (2d ed. 2021).....                                                                                                                                                                       | 4          |
| Massachusetts Department of Public Utilities, <i>Order on Petition of Boston Edison Company, pursuant to G.L. c. 164, '76 and 94, and 220 C.M.R. ' 1.00 et seq., for Review of Its Electric Industry Restructuring Proposal</i> , Massachusetts Department of Public Utilities Case No. 96-23, at 10 (Jan. 28, 1998) .....       | 17         |

**TO THE HONORABLE PUERTO RICO ENERGY BUREAU:**

Following the evidentiary hearing, and in accordance with the Hearing Examiner's Order<sup>1</sup> and PREB's Resolution and Order,<sup>2</sup> Intervenor the Official Committee of Unsecured Creditors of PREPA (the "Committee")<sup>3</sup> respectfully submits this Initial Brief on Rate Design, requesting the Commissioners:

- (i) defer the establishment of any "Legacy Debt Rider"<sup>4</sup> until such time as the United States District Court for the District Court of Puerto Rico (the "Title III Court") overseeing PREPA's bankruptcy case under Title III of PROMESA (the "Title III Case") has adjudicated and determined the final amount of "Legacy Debt"<sup>5</sup> (which, as explained in greater detail herein, is wholly consistent with the recommendation of PREB's own retained consultants); or
- (ii) alternatively, to the extent that PREB nevertheless elects to proceed with some amount, form, or structure of a Legacy Debt Rider (notwithstanding the lack of any evidence presented in this proceeding in support thereof), that any such Legacy Debt Rider properly consider and include the total amount of PREPA's Legacy Debt, including the total amount of "General Unsecured Claims"<sup>6</sup> filed in PREPA's Title III Case, and that any such rider fully preserve the rights of all holders of allowed General Unsecured Claims against PREPA to benefit from any funds collected under any such rider.

The Committee expresses to the Commissioners, the Hearing Examiner, and PREB's staff its genuine appreciation for allowing and facilitating its participation in this rate case, and respectfully represents as follows:

---

<sup>1</sup> *Hearing Examiner's Order Changing Deadlines for Reply Briefs on Annual Revenue Requirement, Initial Briefs on Rate Design, and Reply Briefs on Rate Design*, NEPR-AP-2023-0003 (Jan. 27, 2026).

<sup>2</sup> *Resolution and Order*, NEPR-AP-2023-0003 (Feb. 10, 2026).

<sup>3</sup> The Committee was granted Intervenor status by order dated May 21, 2025.

<sup>4</sup> As used within PREB's *Resolution and Order*, NEPR-AP-2023-0003, App'x at 24 (Feb. 12, 2025).

<sup>5</sup> PREB defined "Legacy Debt" as "PREPA's debts subject to the ongoing Title III" Case. *Resolution and Order*, NEPR-AP-2023-0003, App'x at 24 (Feb. 12, 2025).

<sup>6</sup> As defined in *Fifth Amended Title III Plan of Adjustment of the Puerto Rico Electric Power Authority*, Case No. 17-04780-LTS, ECF No. 5581 at 44 (Bankr. D.P.R. Mar. 28, 2025) (emphasis added) (the "Fifth Amended Plan").

## I. COMMITTEE’S INTEREST IN THIS RATE CASE: LEGACY DEBT RIDER

As the fiduciary appointed to protect the interests of PREPA’s general unsecured creditors, the Committee has a compelling, vested interest in ensuring that general unsecured creditors are not inadvertently overlooked—or, worse, deliberately ignored—in this rate case.<sup>7</sup>

Unfortunately, even though PREB required PREPA’s schedule for “Debt Service Requirements” to include “the **full**, nominal **existing debt** and accrued interest that are subject to the Title III” Case,<sup>8</sup> PREPA’s submissions failed to account for the **billions of dollars** of General Unsecured Claims against PREPA.<sup>9</sup> As the Financial Oversight and Management Board for Puerto Rico (the “Oversight Board”) observed in its proposed disclosure statement filed in PREPA’s Title III Case:

Currently, 2,406 General Unsecured Claims asserting liabilities totaling **\$4.9 billion** remain outstanding. Several of those remaining claims are subject to Oversight Board claim objections that are pending court orders; excluding claims pending an objection, 1,750 General Unsecured Claims asserting approximately **\$2.1 billion** remain pending against PREPA.<sup>10</sup>

The Committee opposes any Legacy Debt Rider that expressly, or impliedly, ignores general unsecured creditors. In fact, the architect of the proposed Legacy Debt Rider, Mr. Sam Shannon, clarified that the phrase “PREPA’s Legacy Debt” should encompass **all** of PREPA’s **debt** as determined by the Title III Court, without PREB preferring or elevating certain types of claims over others:

MR. SAM SHANNON:

Prefacing with I am a layman in this area, [the phrase “PREPA’s Legacy Debt”] is to reflect **the amount that PREPA would be required to pay in the fiscal year, subject to order as the resolution of the Title III case.**

MR. SCOTT HEMPLING:

Pay to whom?

---

<sup>7</sup> During the evidentiary hearing in this rate case, the Hearing Examiner inquired about the Committee’s aims and motivations in participating in this rate case. *See* 12/11 Tr. 273:25 – 274:6 (“MR. SCOTT HEMPLING: ... What’s the unsecured creditors interest in this issue? And don’t advocate just tell me ... what’s the connection between your clients ... self-interest and what we’re going to learn here sir.”).

<sup>8</sup> *Resolution and Order*, NEPR-AP-2023-0003, App’x at 24, 29 (Feb. 12, 2025).

<sup>9</sup> Ex. 39, Schedule B-3:45-63 (providing line items for “Fuel Lines,” “Legacy Bonds,” and “Pension Obligation”—but not holders of General Unsecured Claims, nor any of the myriad other creditors in PREPA’s Title III Case).

<sup>10</sup> *Disclosure Statement for Fifth Amended Title III Plan of Adjustment of the Puerto Rico Electric Power Authority*, Case No. 17-04780-LTS, ECF No. 5582 at 60 (Bankr. D.P.R. Mar. 28, 2025) (emphasis added).

MR. SAM SHANNON:

**Whoever the court says should get the money.** It's an expense line for PREPA that comes out of the resolution of the Title III case.

12/15 Tr. 415:13-416:10 (emphasis added).<sup>11</sup> Moreover, the Committee has a vested interest in ensuring that any Legacy Debt Rider is fully consistent with a yet-to-be confirmed Title III plan of adjustment for PREPA, including the treatment provided therein for PREPA's various classes of creditors. *See, infra*, Part III (discussing this and other undeterminable prerequisites to any implementation of a Legacy Debt Rider, none of which are within this evidentiary record).

For these reasons, and as further detailed below, the Committee respectfully requests that the Commissioners not implement any Legacy Debt Rider at this time and revisit the issue, if at all, only after the Title III Court has determined the full amount and treatment of PREPA's Legacy Debt. Only then will there be the requisite clarity and evidentiary foundation that Puerto Rico law requires before proceeding with any such rider. Alternatively, and solely if a placeholder rider is nonetheless included within the tariff book, any such rider should fully preserve the rights of PREPA's general unsecured creditors to benefit from any funds collected under any such rider.

## **II. ANY LEGACY DEBT RIDER IS PREMATURE AND LACKS NECESSARY EVIDENTIARY FOUNDATION**

In light of PREPA's pending and unresolved Title III Case, implementation of any Legacy Debt Rider would be premature at this time and predicated on an inadequate and faulty evidentiary record. Indeed, this is why other regulators faced with an electric utility's pending bankruptcy case have awaited the outcome of that bankruptcy before developing any mechanism to collect funds from ratepayers for the repayment of the very debt subject to the restructuring process.

On the importance of an evidentiary record, the Hearing Examiner previously made the following published remarks:

Regulators act. They gather information, make rules, adjudicate disputes, issue orders and bring enforcement cases. These actions must heed procedural law, as established by the Constitution, statutes and a commission's own rules. **Procedural law induces accountability:** by empowering the public to observe and influence agency decisionmaking, and by authorizing courts to review the results for lawfulness. **Procedural law also protects against arbitrariness—actions lacking in fact, logic or legal authority—**whether that arbitrariness is committed by regulators

---

<sup>11</sup> Unless noted with "Final Tr.", citations are to draft transcripts.

setting rates, imposing penalties or passing on mergers; or by utilities taking private land or cutting off service.

Hempling, Scott, *Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction*, Ch. 1.B.4. P. 4. (2d ed. 2021) (emphasis added). The Supreme Court of Puerto Rico has articulated that decisions issued by administrative forums, akin to PREB, must have “a rational basis supported by **substantial evidence** that sustains the decision.” *Rebollo v. Yiyi Motors*, 161 DPR 69, 76 (2004) (emphasis added and translation ours). “[A] lower court (or a competent administrative forum) must develop a complete file which includes the determined facts based on the evidence that was presented[.]” *Maldonado Pagán v. Departamento de Corrección y Rehabilitación*, KLRA202100183, 2021 PR App. LEXIS 1085, at \*7 (Apr. 27, 2021) (translation ours), concurring opinion, relying on *Dávila Nieves v. Meléndez Marín*, 187 DPR 750 (2013). In the particular case of administrative decisions, courts have repeatedly upheld the importance of agencies developing and creating a “**complete and substantial**” record in order to be in position to render their decisions. *See Consejo de Titulares del Condominio Atl. v. Mapfre Praico Ins. Co.*, KLAN202000468, 2020 PR App. LEXIS 1436, at \*26 (Aug. 31, 2020) (emphasis added and translation ours); *De León v. Keleher*, KLCE201800796, 2018 PR App. LEXIS 2043, at \*36 (June 27, 2018), relying on *Oficina de la Procuradora del Paciente v. MCS*, 163 DPR 21 (2004).

In this case, that essential evidentiary record is not only entirely lacking with respect to the substance of a Legacy Debt Rider, but is also fundamentally flawed, as detailed below.<sup>12</sup>

**A. Facially Incorrect Filings on PREPA’s Legacy Debt Can Provide No Foundation for a Legacy Debt Rider**

PREB’s February 12, 2025 Resolution and Order, which established the filing requirements for this rate case, defined “Legacy Debt” as “PREPA’s debts subject to the ongoing Title III process.” *Id.* It also mandated that PREPA’s rate application “shall contain,” as “Schedule B-3,” “the debt service requirement associated with each of two scenarios:” (i) a “Low Scenario,” of the Oversight Board’s “most recent public proposal for settlement of the debt that is the subject to the Title III” Case; and (ii) a “Full Scenario,” of “the **full, nominal existing**

---

<sup>12</sup> The Committee notes the “Bondholders” (as defined in their *Initial Post-Hearing Brief on the Revenue Requirement*) argued in that brief that the utility had not met its burden in this rate case. *Id.*, Case No. NEPR-AP-2023-0003 at 1 (Jan. 23, 2026). Insofar as the Legacy Debt Rider is concerned, the Committee agrees that the utility has not met its burden. No “sufficient ‘evidence and documents’ to permit PREB to assess comprehensively the relevant factors” are within this evidentiary record. *Id.*; *see also* 22 L.P.R.A. § 1054x(a)-(b).

**debt** and accrued interest that **are subject to the Title III” Case**. *Id.* “Schedule B-4” was required to contain “PREPA’s proposed Margin” “for each of the debt service requirements identified in Schedule B-3.” *Id.* at 24, 29.

These clear directions were not followed. As filed, Schedule B-3 (“Debt Service Requirements”) and Schedule B-4 (“Proposed Margin on Debt Service Requirements”) fail to take General Unsecured Claims against PREPA into account<sup>13</sup> and are, therefore, fundamentally flawed. For this reason alone, no form of a Legacy Debt Rider can be implemented at this time—or on this deficient record.<sup>14</sup>

Schedules B-3 and B-4 were cited in and attached to the Direct Testimony of Mr. Andrew Smith, LUMA’s CFO.<sup>15</sup> Yet, neither Mr. Smith nor any LUMA representative was able to certify and/or substantiate any of the Legacy Debt figures contained in Schedule B-3 and B-4. Nor did LUMA produce any of the information the Committee requested to answer fundamental, foundational questions about these two schedules. The Committee sent LUMA requests for information (“ROI”) asking LUMA to, for example:

- i. “Please confirm no scenario within Schedule B-3 [and B-4] accounts for general unsecured claims that have been asserted against PREPA in its Title III Case....” (*Id.* OCUCP-of-LUMA-RR-86, -89).
- ii. “Please confirm no scenario within Schedule B-3 accounts for any payment to the holders of general unsecured claims within PREPA’s Title III Case ....” (*Id.* OCUCP-of-LUMA-RR-87).
- iii. “Please list (identifying with specificity) or provide in response to this ROI all documents that you reviewed, considered, or relied upon in creating Schedule B-3 or Schedule B-4 and, for each document, explain how it was used (if at all).” (*Id.* OCUCP-of-LUMA-RR-91).

But the certification of Mr. Alejandro Figueroa, LUMA’s Chief Regulatory Officer, confirmed

---

<sup>13</sup> While the Title III Court is the only proper forum for determining the amount and treatment of the Bondholders’ claim against PREPA, the Committee memorializes, here, its disagreement with the Bondholders’ contention that “the First Circuit ruled that Bondholders’ \$8.5B claim is fully secured by PREPA’s Net Revenues.” *Bondholders’ Initial Post-Hearing Brief on the Revenue Requirement*, Case No. NEPR-AP-2023-0003 at 89 (Jan. 23, 2026). Rather, the Bondholders are only secured **to the extent** that Net Revenues actually exist and, if so, only up to that amount. The Committee (among other parties) contends that the Bondholders’ claim, which the First Circuit has held is a non-recourse obligation, is secured only by PREPA’s Net Revenues, **less** various deductions. The amount of that secured claim has not been determined by the Title III Court, much less the First Circuit. For example, and in the opinion the Bondholders refer to, the First Circuit expressly stated it “d[id] **not** decide what effect, if any, confirmation of a plan of reorganization will have on the [B]ondholders’ security interest, **nor** d[id] it attempt to estimate the economic value of that security interest.” *In re Fin. Oversight & Mgmt. Bd. for P.R.*, 121 F.4th 280, 290 (1st Cir. 2024) (emphasis added).

<sup>14</sup> See *Objection of Official Committee of Unsecured Creditors of PREPA to Applicant Testimony, Intervenor Testimony, and PREB Consultant Reports*, Case No. NEPR-AP-2023-0003 (Oct. 31, 2024).

<sup>15</sup> Ex. 2, 4:87-5:96.

that LUMA could not answer any of these questions. *See also* Response: OCUCP-of-LUMA-RR-86 to -91. This is because the information contained in Schedules B-3 and B-4 did not originate from LUMA, but PREPA. As LUMA’s counsel explained, as to **each and every** ROI the Committee sent to LUMA:

LUMA has identified that certain information requested is not within its possession, was **provided solely by PREPA and PREPA is the only party in possession of responsive information**. These items are listed in the table below[, which then repeated all of the Committee’s ROIs in full]. LUMA will respond, for the record, that this information is not available to it, but we are providing this notice in advance.

Addendum 1, Nov. 20, 2025 Email from LUMA’s Counsel to Committee’s Counsel.

In turn, PREPA’s responses to the Committee’s ROIs confirmed that “[n]o **scenario within Schedules B-3 accounts for any payment to the holders of general unsecured claims** within PREPA’s Title III case, except to the extent such claims are contemplated to be paid ... from Series A or Series B Bonds issued under the Plan.” PREPA Response to ROI # OCUCP-of-PREPA-RR-93. This admission confirms **both** scenarios of Schedule B-4 are wrong:

- i. the Low Scenario, which was required to reflect the Oversight Board’s “most recent public proposal for settlement” of PREPA’s Legacy Debt, completely ignores the hundreds of millions in cash payments to holders of General Unsecured Claims, as provided under PREPA’s proposed Fifth Amended Plan; and
- ii. the Full Scenario, which was required to include “the **full, nominal existing**” Legacy Debt, includes no mention of General Unsecured Claims whatsoever. PREPA’s references to “Series A and Series B Bonds issued under the Plan” tacitly acknowledges these two schedules are logically flawed and not fit for purpose because Series A and Series B Bonds would only be issued after the Title III Court has confirmed the Fifth Amended Plan that contains various settlements proposed by the Oversight Board (*i.e.*, only relevant to the “Low Scenario”). By definition, a “Full Scenario” that **assumes** the confirmation of a plan of adjustment, and approval of settlements embedded within it, is non-compliant because it cannot, and does not, include the “full” amount of PREPA’s Legacy Debt.

In short, Schedules B-3 and B-4 are logically flawed and mathematically incorrect by **multi-billion-dollar margins**. *Cf.* 12/15 Tr. 311:2-8 (“MR. SCOTT HEMPLING: “That’s what we’re here for, ... to help the Bureau make the best possible decision on **a record that is trustworthy**”

(emphasis added).). And through the close of the evidentiary hearing, there was no effort to correct Schedules B-3 and B-4. Consequently, no evidence in the record provides the factual and evidentiary predicate on which PREB could base, as it must, implementation of any form of a Legacy Debt Rider.<sup>16</sup>

In fact, PREB’s own consultants support the same fate for the Legacy Debt Rider as the Committee. Messrs. Ralph C. Smith and Mark S. Dady concluded that the Legacy Debt Rider should **not** be implemented during this rate case. Instead, they sensibly recommend that PREB wait until PREPA’s Title III Case has concluded and the amount of PREPA’s Legacy Debt has been determined:

[D]eveloping a Legacy Debt Rider surcharge, we believe, would be **more appropriately done after the Title III Court has determined what PREPA’s Legacy Debt Obligation is.**

...

Concerning the development of a Legacy Debt Rider surcharge, we recommend that be deferred **until there is a resolution of PREPA’s Legacy Debt Obligation by the Title III Court. After such a final determination has been obtained**, the development of an appropriate method of charging such amounts to ratepayers, such as in a Rider, **can be determined as an element of rate design.**

Ex. 62, Smith and Dady Expert Report, Ex. 62 at 26-27 (emphasis added).

**B. Waiting to Implement Any Legacy Debt Rider Is Also Consistent with Relevant Precedent**

The bankruptcy cases of two electric utilities—and related U.S. Bankruptcy Courts’ and regulators’ dockets—are **actual precedent** the Commissioners should follow (and cite in their reasoning): Entergy New Orleans (in 2007) and PG&E (in 2020). Both cases instructively demonstrate how other regulators prudently chose to await the outcome of a utility’s bankruptcy case.

**a. *Entergy New Orleans***

Following Hurricane Katrina and the costs of system restoration, exodus of customers, and uncollectable customer accounts, Entergy New Orleans (“ENO”) commenced a chapter 11 bankruptcy case. That process resulted in a plan of reorganization that restructured nearly a

---

<sup>16</sup> The absence of the evidence that must be the foundation for any implementation, by PREB, of any form of the Legacy Debt Rider is unsurprising, but gravely consequential. The evidence closed without any party or participant—or their respective experts—providing any “ideas” on any format, structure, or amount that PREB could assess in determining even the bare bones of a Legacy Debt Rider.

quarter billion dollars of legacy debt.<sup>17</sup> The bankruptcy case of this utility is instructive for PREB because it illustrates deference to the bankruptcy process and that other regulators have delayed the determination and implementation of a mechanism to collect from ratepayers the funds to repay prepetition, legacy debt until **after** the amount and treatment of that debt was determined by the bankruptcy court and the bankruptcy case had reached its conclusion. The regulators' determination and implementation of any such mechanism to collect from ratepayers was left for a future rate case.

In particular, ENO sought guidance from its regulator—the New Orleans City Council (“NOCC”)—as to how to pay for ENO's legacy debt obligations.<sup>18</sup> The NOCC instructed ENO to coordinate with the Louisiana Recovery Authority regarding Community Development Block Grants to assist with providing the necessary funds to remediate the system, while not burdening ratepayers. Importantly, however, the NOCC indicated that any storm costs in excess of the allocated government funds **would be addressed in a later base rate case**.<sup>19</sup> The NOCC did not expressly comment on the amount of legacy debt, letting the bankruptcy court determine that amount in the bankruptcy case.<sup>20</sup> Nor did NOCC develop a “rider,” while ENO's bankruptcy case remained underway, to facilitate the subsequent collection of amounts to repay legacy debt in the future.

#### ***b. PG&E***

PG&E's most recent bankruptcy case was filed in 2019 and resulted in a plan of reorganization confirmed in 2020 (and PG&E's financial distress precipitating that filing shares a common factual genesis as the “Wildfire Fund” Dr. Tierney references, discussed below). The context and path followed in the PG&E case are critical for the Commissioners in assessing the proper approach and sequence here to address PREPA's Legacy Debt. PG&E's bankruptcy case was, first and foremost, centered on PG&E's plan of reorganization that provided for the

---

<sup>17</sup> *Fourth Amended Disclosure Statement for the Fourth Amended Chapter 11 Plan of Reorganization of Entergy New Orleans, Inc., As Modified, In re Entergy New Orleans, Inc.*, Case No. 05-17697, ECF No. 1676 at 5-9, 18-47 (Bankr. E.D. La. Feb. 5, 2007) (“ENO Fourth Amended Disclosure Statement”); *see also Findings of Fact and Conclusions of Law Regarding the Confirmation of the Fourth Amended Chapter 11 Plan of Reorganization of Entergy New Orleans, Inc., As Modified, In re Entergy New Orleans, Inc.*, Case No. 05-17697, ECF No. 1989 at 1 (Bankr. E.D. La. May 7, 2007).

<sup>18</sup> Addendum 2, The New Orleans City Council, R-06-459, *Resolution and Order Approving Agreement in Principle* (Oct. 27, 2006) at 5-6. *See also* Entergy Corporation Form 10-k for the Fiscal Year Ended December 31, 2007.

<sup>19</sup> ENO Fourth Amended Disclosure Statement at 48.

<sup>20</sup> *Id.* at 18-47.

restructuring of \$57.65 billion in legacy debt.<sup>21</sup> **Afterward**, developments within the bankruptcy case resulted in “only one plan – the PG&E Plan – remain[ing] before” its regulator, the California Public Utilities Commission (“CPUC”), for the regulator’s consideration.<sup>22</sup> The CPUC accepted that plan of reorganization with a few modifications, primarily related to the governance of PG&E, and enhancing safety performance by instituting new penalties if safety standards were not met.<sup>23</sup> In the CPUC’s decision approving the plan, the CPUC did not adjust the total amount of legacy debt that was restructured through PG&E’s plan of reorganization; instead the CPUC focused its efforts on optimizing the recovery of the legacy debt amount and directed PG&E to pursue a rate-neutral securitization to refinance the legacy debt—in contrast to the imposition of a rate increase or debt rider.<sup>24</sup>

Nor did the CPUC implement a “rider” for the Wildfire Fund [Non-Bypassable Charge]—prior to the resolution of PG&E’s bankruptcy case—so that funds could be collected to pay for PG&E’s legacy debt. Rather, it was “a statutory requirement for PG&E to access the wildfire fund going forward,” and “for PG&E to participate in the wildfire fund, **the Bankruptcy Court** and the Commission **must approve the reorganization plan** and other documents resolving the insolvency proceeding ....”<sup>25</sup> Indeed, within PG&E’s bankruptcy case, the Wildfire Fund was dubbed the “**Go-Forward** Wildfire Fund,” in that it was only to “pay for liabilities arising in connection with wildfires that occur **after July 12, 2019**,” *i.e.*, nearly six months **after** PG&E’s bankruptcy began.<sup>26</sup>

C. **Both Experts that Advocate for Legacy Debt Rider Offer No Reliable Evidence of Amount, Format, or Structure**

In the face of the deficient evidentiary record and the expressed concerns about building and having an adequate record, only two experts in this rate case advocate for the Legacy Debt Rider: (i) Mr. Sam Shannon, who is retained by LUMA and employed by Guidehouse; and

<sup>21</sup> CPUC, *Pacific Gas and Electric Company’s (U 39 E) Reply Brief Regarding Evidentiary Hearing and Assigned Commissioner Proposal Comments* (Mar. 26, 2020); *Debtors’ and Shareholder Proponents’ Joint Chapter 11 Plan of Reorganization*, Case No. 19-30088, ECF No. 5590 at 46 (Bankr. N.D. Cal. Jan. 31, 2020).

<sup>22</sup> Addendum 3, CPUC, *Decision Approving Reorganization Plan* (May 28, 2020) at 4-7.

<sup>23</sup> *Id.* at 110-112.

<sup>24</sup> *Id.* at 78.

<sup>25</sup> *Id.* at 10-11 (emphasis added).

<sup>26</sup> *Debtors’ Motion ... for Entry of an Order ... Approving Case Resolution Contingency Process...*, Case No. 19-30088, ECF No. 6398 at 10-11 (Bankr. S.D. Ca. Mar. 30, 2020) (emphasis added).

(ii) Dr. Susan Tierney, a paid expert by the Bondholders. Neither challenge (or even dispute) the fact that there is an insufficient evidentiary foundation for imposing such a rider at this time.

**1. Mr. Sam Shannon**

Mr. Shannon was proffered by LUMA as its expert on the Legacy Debt Rider. But he conceded the starting point for any Legacy Debt Rider must be the out-of-bounds **amount of the debt**, which remains unknown at this time.<sup>27</sup>

[QUESTION]

[Y]ou said I have to “**first allocate the legacy debt.**” What is the **second or any subsequent steps** that you’re referring to, or that may follow that?

MR. SAM SHANNON:

**There aren’t any subsequent steps after that.**

12/15 Tr. 420:5-12 (emphasis added); Ex. 20, S. Shannon Direct Testimony 16:326-329 (“In order to allocate the net income component to customer classes, I had to allocate the legacy debt first.”). Mr. Shannon also agreed that the **allocation of legacy debt** (which is the *sine qua non* of implementing a Legacy Debt Rider) can occur only **after** that amount has been established by the Title III Court.

[QUESTION]

Do you agree with the premise that you have to know what you are splitting up or dividing up before you can split it up or divide it up?

MR. SAM SHANNON:

Yes.

12/15 Tr. 418:13-15.

MR. SAM SHANNON

The basic purpose of a cost of service study is to- the fancy term is allocate costs- all costs among all the different customer classes, so that you can determine what the final revenue allocation from the mathematical model is resulting.

*Id.* 418:10-19.

Even as to this single-step of “allocation,” Mr. Shannon provides incomplete (at best) evidence on how PREPA’s Legacy Debt may, or should, be allocated—and no guidance

---

<sup>27</sup> The dearth of evidentiary foundation for either the existence, or structure, of the Legacy Debt Rider results from PREB’s own order and guardrails within this rate case, which precluded any “testimony or cross examination” on either: (i) “any amount of legacy debt, nor on any principle or method for determining such amount”; or (ii) “the role of legacy debt in practicability analysis.” Nov. 13 Order at 2. Notably, the Commissioners’ reasoning for excluding the latter from the evidentiary record was that “the record contains no factual foundation for such inquiry.” *Id.* By that same reasoning, PREB also cannot act on the Legacy Debt Rider within this rate case.

whatsoever for PREB on how to allocate the myriad types/categories of PREPA's Legacy Debt, other than the two that were (underinclusively) listed on Schedules B-3 and B-4:

[QUESTION]

[Y]ou only made two (2) allocations of PREPA's Legacy Debt Obligations. Is that right?

MR. SAM SHANNON:

Oh, yes, the pension was separate from the Legacy Debt. Yes, that's correct.

[QUESTION]

And do you make any other recommendations for the PREB in order to allocate potential types or categories of PREPA's Title III debt **other than legacy bonds or pensions**?

WITNESS, MR. SAM SHANNON:

**No, I do not.**

[QUESTION]

And of those two types or categories of PREPA's legacy debt, that you did allocate; the first being PREPA bonds, and the second being pensions. **Am I correct that you allocated each of those two (2) items in two (2) different ways?**

MR. SAM SHANNON:

Subject to check here. **Yes, those are allocated differently.**

*Id.* 420:14-421:19 (emphasis added). To summarize, the only evidence in the record about the allocation of PREPA's Legacy Debt: (i) did not consider multiple categories of PREPA's debt, such as holders of General Unsecured Claims and the fuel line lenders; and (ii) allocated the **two** types/categories of PREPA's Legacy Debt that Mr. Shannon did consider (*i.e.*, "legacy bonds" and "pensions") in two **different** ways—meaning the evidentiary record provides no guidance for PREB about how to allocate any type/category of PREPA's Legacy Debt (other than "legacy bonds" and "pensions"). *Id.*

## **2. Dr. Susan Tierney**

Other than Mr. Shannon, the only other evidence or testimony in support of the Legacy Debt Rider originated from the Bondholders through their expert, Dr. Susan Tierney. But Dr. Tierney's own testimony and admissions on cross-examination undermine the credibility of her conclusions and recommendations, and come nowhere close to providing any form of evidentiary foundation for the Legacy Debt Rider.

### ***a. Dr. Tierney Offers No Support for Any Amount, Form, or Structure of a Legacy Debt Rider***

To the extent PREB elects to implement a Legacy Debt Rider, the range of options is infinite. An endless number of permutations exist for structuring any Legacy Debt Rider. *See* 12/9 Tr. 378:13-17 ("[QUESTION:] Do you acknowledge that there's more than one way to design a legacy debt rider? DR. SUSAN TIERNEY: Yes.").

Yet, no one proposed a structure for the Legacy Debt Rider, and nothing exists within the evidentiary record to support any structure that PREB would, otherwise, be left to construct from whole cloth. Dr. Tierney resolutely declined to offer any opinion on how a Legacy Debt Rider could, or should, be structured:<sup>28</sup>

[QUESTION]

Are you proposing any structure for the legacy debt rider?

DR. SUSAN TIERNEY:

I did **not** propose one.

[QUESTION]

So, nowhere in your testimony, whether you're answering or your rebuttal, have you described how you suggest a legacy debt rider could or should work?

DR. SUSAN TIERNEY:

**Not** in my written testimony, **no**."

12/9 Tr. 377:19:-378:5 (emphasis added); *see also id.* 404:15-22 ("[QUESTION] In your proposed legacy debt rider, are you **making any recommendation about how to allocate the cost of legacy debt** across customer classes of residential, commercial, and industrial?

DR. SUSAN TIERNEY: **I did not**, but won't be surprised if I'm asked about that." (emphasis added)).

Dr. Tierney acknowledges that **someone** must create a structure for the Legacy Debt Rider (even though she did not) and also acknowledges that any such structure must be based on **something** in evidence (even though she does not offer it):

[QUESTION]

...

**My question is, doesn't someone have to determine that** [*i.e.*, how to allocate the cost of legacy debt across customer classes of residential, commercial, and industrial] **in the future?**

DR. SUSAN TIERNEY:

Yes.

[QUESTION]

And who determines that in the future under your legacy debt rider you're proposing?

DR. SUSAN TIERNEY:

The Bureau.

[QUESTION]

On what evidentiary record would they be asked to do that?

DR. SUSAN TIERNEY:

I understand that **there will be discussions in the rate design panel on that topic** amongst other rate design topics.

---

<sup>28</sup> Mr. Shannon similarly offers PREB only a nebulous construct devoid of details. *See* 12/16 Tr. 267:4-10 ("[QUESTION]: But you don't make any recommendation about what percentage or piece or component should be variable and which percentage or piece or component should be fixed. Do I have that right? MR. SAM SHANNON: That's correct.").

*Id.* 404:15-405:15. Dr. Tierney presumed that something would be placed into the evidentiary record in this rate case to provide the contours of the rate design for and structure of the Legacy Debt Rider.<sup>29</sup> But it never was.

***b. Dr. Tierney Is Under-Informed, and Outright Mistaken, About PREPA's Current and Historical Riders***

Expert witnesses offer opinions, and the sole opinion Dr. Tierney offered was that this rate case should implement a rider for Legacy Debt. Dr. Tierney, though, was “unfamiliar” with other riders, past or present, utilized by PREPA—and leaned on that lack of familiarity to avoid answering questions that undermined the thesis she presented to PREB:

MR. SCOTT HEMPLING:

...

Are you familiar with the uh, how the rider works or the uh, fuel writer works in this case?

DR. SUSAN TIERNEY:

**Only in the most general way** and I don't remember referring to it. I'm sure the record's clear but I don't remember referring to the fuel rider.

MR. SCOTT HEMPLING:

All right, well, the-the problem is **[Dr. Tierney] doesn't know enough about the rider to give you a useful answer...**

12/9 Tr. 96:10-97:5 (emphasis added).

And even where Dr. Tierney was able to testify about some familiarity with PREPA's riders, she made multiple, blatant mistakes when pressed to provide more detail on same. For example, Dr. Tierney likened her proposed Legacy Debt Rider to the 2017 Energy Efficiency Rider, contending that PREB would merely be doing what it has done before, by implementing a rider that depends on future, yet-to-occur developments:

---

<sup>29</sup> When Commissioner Ramos-Soegaard asked Dr. Tierney whether she was proposing a Legacy Debt Rider “any different from” the “securitization charge rider,” she could provide only an equivocal answer that, again, presupposed the rate design of the Legacy Debt Rider would be discussed—a discussion that never occurred:

[COMMISSIONER]:

Are you, what you're proposing, is it any different from that?

DR. SUSAN TIERNEY:

**Maybe. And here's why I say maybe as opposed to, no. And it's because there will be discussion in this proceeding on rate design, I understand.** So there could be more.

*Id.* 434:5-25 (emphasis added). Of course, that “securitization charge rider” also finds its genesis in the fact that PREB, as a result of prior actions by the Puerto Rico Legislature, was legally obligated to resolve the underlying petition within a constrained time period, so as to avoid losing jurisdiction to do so. *See, e.g., Restructuring Order*, Case No. CEPR-AP-2016-001 at 8 (June 21, 2016) (“Under Section 6.25A of Act 57-2014, if the Commission does not issue its decision within seventh-five (75) days of receiving a complete Petition, it loses its jurisdiction and the Petition is deemed approved.”).

DR. SUSAN TIERNEY:

I am asking for a rider, suggesting that there be a rider put in place along the lines of what happened in 2017. I think is the year in which as part of the last rate case, the commission adopted **the energy efficiency rider and did not put in place a number and show an amount on customers' bills until there was a funded amount**, a known and measurable amount, that **the Bureau then caused to flow through the rider**. So, the known and measurable amount would be the **information provided to this Bureau coming out of the Title III court that then would begin to flow**.

*Id.* 398:12-399:6 (emphasis added). Dr. Tierney went so far as to claim “precedent in Puerto Rico specifically” exists for what she proposes PREB do in this rate case with the Legacy Debt Rider. Ex. 52, Answering Testimony of Susan Tierney 19:1-4. But that, too, is belied by the facts, including:

- i. No Action by Puerto Rico’s Legislature – The Energy Efficiency Rider was a mandate of public policy established by Puerto Rico’s Legislature through, for example, Act 57-2014 (the Puerto Rico Energy Transformation and RELIEF Act) and Act 17-2019 (the Puerto Rico Energy Public Policy Act). PREB implemented that rider as a mechanism to fulfill these laws:

according to paragraph (i) of Section 6.3 of Act 57-2014, the Energy Bureau has the duty and responsibility to “[e]stablish energy efficiency mechanisms and programs to gradually reach reasonable goals that ensure compliance with the energy public policy.

...

[T]he Energy Bureau APPROVES an initial Energy Efficiency fund of \$13,000,000.00 to be collected from customers through the EE Rider during the period of October 1, 2019 to June 30, 2020

...

[T]he Energy Bureau deems necessary to create the Energy Efficiency fund in order to implement such programs as soon as practicable, in order to start working towards achieving the Energy Efficiency goals established by Act 17-2019 and Act 57-2014.

*Resolution and Order*, NEPR-AP-2018-0003, at 8-9 (Sept. 27, 2019).

- ii. No Simplistic Calculation – Dr. Tierney’s suggestion that a Legacy Debt Rider could simply “begin to flow” after the resolution of PREPA’s Title III Case is a gross oversimplification. Unlike here, where no evidence of any rate design or structure for the Legacy Debt Rider has been introduced, or debated, within this evidentiary hearing (and that rider necessitates allocation among customer classes and

determination of countless other attributes, *supra*, Part II.B.), the Energy Efficiency rider was a straightforward, middle-school math problem:

The EE rider factor is calculated by dividing the total estimated amount to be recovered, \$13,000,000, by the total estimated kWh sales, 11,596,705,845. Therefore, the EE rider factor to be in effect during the period of October 1, 2019 to June 30, 2019 is \$0.001121/kWh.

*Resolution and Order*, NEPR-AP-2018-0003, at 9 (Sept. 27, 2019). In contrast, there is simply no evidence within this evidentiary record to suggest simple division would be appropriate for a Legacy Debt Rider.

- iii. Order of Magnitude Difference – Of course, nothing in this rate case will determine the **amount** of PREPA’s Legacy Debt or **how** it will be repaid, but the Commissioners must appreciate the exponential difference between the cost of energy efficiency programs (measured in millions of dollars) and the potential magnitude of PREPA’s Legacy Debt (measured in billions of dollars). The “initial Energy Efficiency fund” to which Dr. Tierney analogized the Legacy Debt Rider was a meagre \$13 million. Even the under-inclusive Schedule B-3 tallies nearly \$9.5 billion of Legacy Debt, while erroneously ignoring billions more. *See* Ex. 39, Schedule B-3.

*c. Dr. Tierney Erroneously Limited Her Analysis Exclusively to the Bondholders, Thus Ignoring the Total Amount of PREPA’s Legacy Debt*

Dr. Tierney’s expert report, testimony, and suggestion that PREB implement a “rider with a placeholder for the recovery of legacy debt” are premised on her inaccurate and incomplete conception of “legacy debt.” That is, Dr. Tierney recommended that PREB implement a rider by considering **only one** type/category of PREPA’s Legacy Debt: the debt held by her clients:

[QUESTION]

So, I can ask the question with respect to legacy debt, if that provides some clarity, Dr. Tierney. So, my question is, are you making any recommendation or proposal about what types, categories, or classes of PREPA’s legacy debt should be repaid via a legacy debt [r]ider?

...

My question for you about that passage from your testimony is this. Does the legacy debt rider that you’re proposing **only collect funds for the benefit of PREPA’s bondholders?**

DR. SUSAN TIERNEY:

When I was, **yes**, because when I was asked to do my

testimony, **I was asked by the bondholders to talk about the bondholders debt. I was not asked to talk generally about debt.**

12/9 Tr. 375:15-376:15 (emphasis added).

Dr. Tierney's recommendations to PREB, then, must be cabined for what they are: an opinion and conclusion based on the instructions given to her by her clients and not the actual amount of Legacy Debt that is the subject of the Title III Case. Thus, Dr. Tierney's recommendation, which she reached without "think[ing]" of any creditors of PREPA other than those who were paying for her time, should be given zero weight by the Commissioners:

DR. SUSAN TIERNEY:

I was thinking principally about the bondholders' debt. And so, I guess I would say **I didn't think about the other ones.**

*Id.* 382:23-383:1 (emphasis added).

*d. Dr. Tierney Undertook No Search for Similar Situations in Past Utility Bankruptcies to Support Her Conclusions*

Dr. Tierney's analysis and conclusions are also undermined by her decision not to consider how other regulators have dealt with legacy debt subject to an ongoing bankruptcy case. Dr. Tierney made **no attempt** to search for or locate similar situations in prior utility bankruptcy cases, *i.e.*, akin to PREPA's Title III Case. Instead, Dr. Tierney based her opinions on the happenstance of what "occurred to her" after "trying to think," and the Commissioners should place no weight on an expert whose only resource is her own ability to recall from her own memory:

[QUESTION]

What criteria did you utilize when you selected the California wildfire case or study and the Boston Edison case or study?

DR. SUSAN TIERNEY:

I have many decades of experience in the electric industry and its regulation and economics, and **I was trying to think** of situations where there was some amount of money that was not known at the time that a rider was established. **And it occurred to me about those two cases. I did not otherwise do a comprehensive search, but I was aware of those two cases.**

[QUESTION]

So, if I understand your testimony, **you didn't actually look** for other instances where a utility filed for bankruptcy or otherwise found itself before a bankruptcy court, and then a regulator was making a determination about whether or how to have ratepayers pay for the debts or obligations of that utility prior to filing for bankruptcy.

DR. SUSAN TIERNEY:

**No, I did not** use that as a criteria.

12/9 Tr. 409:19-410:17 (emphasis added).

*e. The Two “Examples” Relied on by Dr. Tierney Have No Similarities to PREPA, or PREPA’s Title III Case*

Dr. Tierney relied on two examples that she opined provide the Commissioners with the proper framework to use in determining a Legacy Debt Rider for PREPA’s current situation. *See* Ex. 67, Rebuttal Testimony of Susan Tierney at 1:18-2:7; 4:16; 7:8. The first is “the Wildfire Fund ... established in 2019 by order of the California Public Utilities Commission (‘CPUC’). . . .” *Id.* at 2:3-5. The second is “the transition charge to recover electric utility stranded costs that was established by order of the Massachusetts Department of Public Utilities (‘MDPU’).” *Id.* at 2:5-7. Neither of those “riders” is, in fact, “similar” or of any precedential value for PREB.

Both the CPUC and MDPU were implementing clear, specific legislative mandates; PREB is not. The genesis of the California Wildfire Charge was not the regulator, but California Assembly Bills 1054 and AB 111. The CPUC stated as much in its decision imposing the California Wildfire Fund:

It is important to note that while **the Wildfire Fund is part of the Legislature’s broader response to the threat of catastrophic wildfires set out in AB 1054**, the scope of this proceeding is limited to whether the Commission should exercise its broad ratemaking authority to determine if it is just and reasonable to impose the Wildfire Fund [Non-Bypassable Charge].<sup>30</sup>

The MDPU, too, acknowledged: “The Legislature found that the transition to a competitive generation market ... should provide electric utility investors with a reasonable opportunity to recover prudently incurred costs associated with generation-related assets and obligations,” *i.e.*, through the transition charge.<sup>31</sup> Dr. Tierney conceded to the Hearing Examiner that a “specific mandate” existed from both the California and Massachusetts Legislatures to each respective regulator—**and** that PREB has no such mandate:

DR. SUSAN TIERNEY:

... **They approved those riders because the legislature in each state** said they needed to, that the regulator needed to take action on a type of money that would under certain circumstances

---

<sup>30</sup> Addendum 4, *Decision Approving Imposition of a Non-Bypassable Charge to Support California’s Wildfire Fund and Adopting Rate Agreement Between The California Department of Water Resources and the California Public Utilities Commis[sion]*, Rule No. 19-07-017, at 6 (Oct. 24, 2019) (emphasis added) (hereafter “CPUC Wildfire Fund Decision”).

<sup>31</sup> *Order on Petition of Boston Edison Company, pursuant to G.L. c. 164, ‘76 and 94, and 220 C.M.R. ‘ 1.00 et seq., for Review of Its Electric Industry Restructuring Proposal*, Massachusetts Department of Public Utilities Case No. 96-23, at 10 (Jan. 28, 1998) (hereafter “MDPU Order”).

be included in rates. That was the **legislative footing for those riders....**

12/9 Tr. 401:6-402:12 (emphasis added).

Okay. Now, what counsel is saying is that well that's really, but what he's about to get to is this, that's really different isn't it from a very specific statute that you had in California or in Massachusetts, that mandated that a very specific rider get put into place. There's a difference, right? I'm not saying you're wrong to admit to just give your answer. I'm saying there's a difference, right?

DR. SUSAN TIERNEY:

**The purposes of those statutes were different**, but the mechanics of how things happened in the rate-making context were parallel, in my opinion.

MR. SCOTT HEMPLING:

Right, but whereas **there was a specific mandate in California**, for example, to have a specific rider, **there's not in the Puerto Rico situation a specific mandate to have your specific rider.**

DR. SUSAN TIERNEY:

**That's right.**

*Id.* 403:14-404:11 (emphasis added).<sup>32</sup>

Both the California Wildfire Charge and Massachusetts transition charge were premised on formulaic instructions and exacting detail; PREB has been given no such direction, nor does anything in the evidentiary record enable it to design a rate structure for the Legacy Debt Rider. In California, an "A[ssembly] B[ill] specifie[d] that if the Wildfire Fund [Non-Bypassable Charge] is adopted then it should be collected 'in the same manner as' the current DWR Bond Charge." The CPUC applied the "in the same manner" phrase within that legislative directive to "mean that the Wildfire Fund [Non-Bypassable Charge] should be collected in no different a manner from the DWR Bond Charge," which was "collected on a dollar per kWh basis," and so, therefore, would the Wildfire Fund Non-Bypassable Charge be collected.<sup>33</sup> In addition to the "how" of collection, the "how much" was to-be-collected from ratepayers was also specified to CPUC.<sup>34</sup> For Massachusetts, Dr. Tierney portrays the transition charge as a regulator "adopt[ing] and design[ing] a **rider** as part of an electric utility tariff without knowing the **precise** amount of

---

<sup>32</sup> Dr. Tierney otherwise grappled with broad-brush references to the generalities of "Act 57." *Id.* 404:4-11.

<sup>33</sup> Addendum 4, CPUC Wildfire Fund Decision at 24-25.

<sup>34</sup> Wildfire Fund Administrator, *Annual Report to the California Catastrophe Response Council and the Legislature on Wildfire Fund Operations* at 1 (Aug. 12, 2024) ("The 2019 Wildfire Legislation created a capitalization structure that establishes multiple revenue streams flowing into the Fund to provide approximately \$21 billion in claim-paying capacity to cover eligible claims arising from covered wildfires.").

money that it would eventually need to collect from ratepayers,”<sup>35</sup> but the degree of detail the Massachusetts legislature provided to the MDPU tells a radically different story:

According to the [Electric Industry Restructuring Act, Chapter 164 of the Acts of 1997], categories that may be included in transition costs are the following: (1) the amount of any unrecovered fixed costs for generation-related assets and obligations; (2) the amount of any previously incurred or known liabilities related to nuclear decommissioning and post shutdown obligations associated with nuclear power plants; (3) the unrecovered amount of the reported book balances of existing generation-related regulatory assets; (4) the amount by which the costs of existing purchased power contract commitments exceed the competitive market price for electricity, or the amount necessary to liquidate such contracts; (5) employee-related transition costs; (6) any payment of taxes or payments in lieu of taxes; and (7) any costs to remove and decommission retired structures at certain fossil fuel-fired generation facilities.<sup>36</sup>

Finally, both “examples” Dr. Tierney put forth served the inverse purpose of the proposed Legacy Debt Rider and were subject to a bill impact analysis—unlike the Legacy Debt Rider, which has been subject to no analysis at all. Both the California Wildfire Fund Non-Bypassable Charge and the Massachusetts transition charge were aimed at **saving** ratepayers money: (i) the CPUC concluded, for the California Wildfire Non-Bypassable Charge, “the benefits for ratepayers ... outweigh the incremental charge,” concurring with California’s legislature<sup>37</sup>; and (ii) Massachusetts’ legislature anticipated that the “total rate reduction” resulting from the transition charge’s implementation would “be 15 per cent.”<sup>38</sup> The Legacy Debt Rider, in contrast, can only materially increase the bills of PREPA’s customers.

Dr. Tierney had actual knowledge of (at least) two electric utility bankruptcies (discussed in Part II.B.) but must have chosen not to research their procedural histories before submitting her written or verbal testimony to PREB—despite relying on the California Wildfire Non-Bypassable Charge that was intertwined with PG&E’s emergence from bankruptcy in 2020.<sup>39</sup>

---

<sup>35</sup> Ex. 67, Rebuttal Testimony of Susan Tierney 1:18-2:2 (emphasis added).

<sup>36</sup> MDPU Order at 48 (Jan. 28, 1998).

<sup>37</sup> Addendum 4, CPUC Wildfire Fund Decision at 52 (emphasis added); see Ca. AB 1054 § 1(a)(3) (2019-2020) (“The creation of a wildfire insurance fund will reduce the costs to ratepayers in addressing utility-caused catastrophic wildfires.”).

<sup>38</sup> Commonwealth of Massachusetts, Session Laws Chapter 164, *An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein*, § 1B(B) (1997).

<sup>39</sup> Dr. Tierney confirmed during the evidentiary hearing she had general familiarity with—but, conveniently, not enough knowledge to answer questions about—their histories and attributes that demonstrate why her decision to ignore them is inexcusable. For Entergy New

*f. Dr. Tierney’s Touted Benefits of Premature Implementation of a “Placeholder” Rider Are Speculative and Unquantifiable*

Dr. Tierney testified that efficiency and time savings warrant the establishment of at least the structure of a Legacy Debt Rider. However, Dr. Tierney’s own testimony actually supports a finding by the Commissioners that the proper way in which to proceed is to wait for the Title III Court to determine the amount of PREPA’s Legacy Debt before establishing any Legacy Debt Rider. As Dr. Tierney conceded during cross-examination, there will need to be **another rate case** following the conclusion of PREPA’s Title III Case:

[QUESTION]

... Dr. Tierney, I’d like to turn to you for just a few questions. If I could refer back earlier this morning to your discussion that you had with Ms. Chambers about margin. I think I heard you correctly, but please tell me if not, do you agree that margin should be added into rates after PREPA’s Title III case concludes?

DR. SUSAN TIERNEY:

I uh, I don’t recall saying exactly that. I said that would be an appropriate time if it were to happen after Title III. emerging **after PREPA emerged from the Title III case. There would need to be a rate case**, and the Bureau would need to consider the extent to which there is adequate working capital to signal to capital markets and cover working capital needs so...

12/9 Tr. 91:24-92:16 (emphasis added).

The evidentiary record is also—dispositively—lacking anything to establish the **existence** of any benefit from implementing a “placeholder” rider now, much less the **amount** of that benefit. Dr. Tierney “only qualitatively” weighed the drawbacks of delaying the implementation of a Legacy Debt Rider against (her understanding of) the benefit of implementing a Legacy Debt Rider **now**, as opposed to **later** in the new rate case that she says PREB should conduct promptly following the conclusion of PREPA’s Title III Case. At best, and as Dr. Tierney conceded, she is simply “imagining” collection from ratepayers could start sooner—but readily admitted she has no basis for her speculative predictions, and she also does not know enough about PREB’s procedures to make an intelligent, fact-grounded comparison:

---

Orleans: “[QUESTION] Are you familiar with Entergy New Orleans and its Chapter 11 filing? DR. SUSAN TIERNEY: Only in the most general way. ... [QUESTION] So, if I had detailed questions for you about the procedural history of that bankruptcy, or how the New Orleans City Council decided to allow or disallow a rider to pay for pre-petition obligations, you would not be able to answer those. Is that right? DR. SUSAN TIERNEY: **That’s correct.**” 12/9 Tr. 410:18-411:16 (emphasis added). And, for PG&E’s 2020 bankruptcy: “[QUESTION] Are you familiar with PG&E’s California[] bankruptcy filing that it did in roughly 2020? DR. SUSAN TIERNEY: Yes, generally. Yes, generally.” *Id.* 411:17-412:15.

DR. SUSAN TIERNEY:

...

A new docket is opened, **I can imagine** if it goes through a process akin to this one, that could be four to six month period. **I'm imagining that. I don't know** if the current schedule about a rate case filing with the 180 days after a certified complete filing is made, whether we're talking about a six month period then. Then there are decisions that would have to be made by the Bureau and then the commencement of implementation. **Something that I am imagining could be** plus net six months or more compared to the first scenario that I described. So that's how I thought about it in terms of these procedural steps.

*Id.* 387:12-390:22 (emphasis added). Dr. Tierney's "imagination" is even more troubling

because it is not grounded in any familiarity with (or observation) of PREB, which one

Commissioner astutely recognized, confronting Dr. Tierney about her speculation:

COMMISSIONER TORRES-MIRANDA:

Okay. In your experience, once the bankruptcy court does its final decision, in this case we call it Title III, and they say it's such an amount, what happens then that it goes to the regulators — let's say to the commissioners— what happens then in your experience?

**I want to know the timeline once the court... On your experience, once the court makes a final decision on what the commissioners go through a process and the time it takes to actually sharpen the bill?**

DR. SUSAN A. TIERNEY:

The facts of the Pacific Gas & Electric bankruptcies were a little bit different. The regulators had to make decisions about new rates, **even with the restructuring plan having been approved by the bankruptcy court** —and I think that **there was a timing of the two sets of decisions by the regulators and the bankruptcy judge that were very close in time— and they were all aware that they were on a very similar timeline. So, it is not the same in that regard.**

COMMISSIONER TORRES-MIRANDA:

Okay. **How long do you think it would take us here in Puerto Rico, this commission, when Title III comes with a final decision? It has to come to PREB**, because that's how it's mentioned in the court, **PREB does what it does on the rate case. Would it take six months?**

And the reason I'm doing this question is that **you're saying, "Put the rider now because we're going to save six months in the administrative process," and I just don't see that.**

DR. SUSAN TIERNEY:

**I don't know which provision of your laws this would come under**, or whether there is a time limit on your review of a compliance filing after a Title III decision.

And in my sentence, **I was assuming that** there was a mechanism that was outlined in this rate case in the tariff book. And that the compliance filing would be a number that would flow through again with the compliance filing.

12/9 Final Tr. 473:24-475:18 (emphasis added). Dr. Tierney's inability to ground her

speculation in facts or any source should be alarming and, so too, is the total absence of any

“mechanism ... outlined” for the Legacy Debt Rider within the evidentiary record of this rate case.

**III. AWAITING THE OUTCOME OF PREPA’S TITLE III CASE IS THE ONLY RATIONAL OUTCOME—CONSISTENT WITH THE “JUST AND REASONABLE” STANDARD**

While PREB is faced with many difficult decisions within this rate case, tabling the Legacy Debt Rider—and deferring any and all action by PREB on Legacy Debt until the PREPA’s Title III Case has concluded—is not one of them. This approach is pragmatic, sensible, and consistent with how other regulators have handled electric utilities in bankruptcy. Dr. Tierney would not, and did not, “say that [it is] wrong” for “the PREB commissioners to decide to wait until there is a known outcome of the Title III” Case. 12/9 Tr. 385:24-286:9. With deferral and deference to the bankruptcy case perfectly acceptable and consistent with regulatory precedent, rushing to implement a “placeholder” rider cannot be squared with the compelling need before PREB for predictability, along with stability, in PREPA’s electricity rates:

[COMMISSIONER] TORRES-MIRANDA:

[T]he people of Puerto Rico, they need stability. As Mr. Shannon said, not just the commercial industrial, also the residential. And we can’t be having this stress given to the people of Puerto Rico every three months that we have now with the, with the factors of the fuel and changing the [unintelligible] determinants every year. If it goes, it means it’s a decrease in the rates that would be fine, but if it’s an increase ....

12/16 Tr. 45:1-20.

MR. SAM SHANNON:

[L]arge industrial customers and the commercial customers, they value predictability and rates. And so, knowing what the rates are for the next three years is valuable to that segment of the population. Likewise, I would anticipate that the renewable energy community, knowing what the rates are going to be for the next three years is valuable to that industry. So there is value in the certainty of knowing what the rates will be.

*Id.* 40:4-41-14.

The notion of a “placeholder” Legacy Debt Rider, **especially** on a non-existent evidentiary record (as is the case here), fails to satisfy Puerto Rico’s established legal standards while also falling woefully short of comporting with due process. The form of the Legacy Debt Rider at issue within the evidentiary hearing was, to be charitable, evolving and nondescript. PREB is prohibited, as a matter of Puerto Rico law, from implementing a different rider than the one LUMA proposed (much less fabricating its own rate design or structure for the Legacy Debt Rider behind closed doors). Section 6.25 of Act 57 does not allow PREB to fabricate the

contours of a Legacy Debt Rider without any opportunity for: (i) cross examination on the novel, alternative design(s)/structure(s); (ii) panel/expert testimony about those alternatives; (iii) public comment; (iv) allocation between customer classes and whether to use a fixed, variable, hybrid, or bypassable/non-bypassable charge; or (v) other attributes or pitfalls.

**Any modification** to a rate proposed, . . . whether to increase or decrease the same, **shall undergo an evidentiary and a public hearing process to be held by the Commission** to determine whether the proposed change is just and reasonable and consistent with sound fiscal and operational practices that provide for a reliable and adequate service, at the lowest reasonable cost.

22 L.P.R.A. § 1054x(c) (emphasis added); Section 6.25(f) of Act 57-2014 (“Upon concluding the public hearing process, the Energy Bureau shall issue its final determination with regards to the rate review request and establish the electricity rate it deems just and reasonable. Such a determination shall be duly grounded and comply with all the safeguards of the due process of law applicable to the final determinations of administrative agencies.”).

Both proponents of the concept of a Legacy Debt Rider concede they were only asking for a to-be-completed “placeholder”:

[QUESTION]

And do you know if there’s been a newer or updated plan of adjustment since then?

MR. SAM SHANNON:

[T]his is **kind of a placeholder we just need the ... tariff to be established in this case ...**

12/16 Tr. 262:3-13 (emphasis added).

DR. SUSAN TIERNEY

I understand that **there are a lot of to-be-filled-in elements of how the recovery would be designed** when there would be a compliance filing ....

*Id.* 273:20-274:10. PREB has no means of fulfilling its legal obligations based on the empty evidentiary record, and it cannot make policy decisions without any opportunity for meaningful and substantive input, argument, or briefing. Where, as here, no evidence has been taken about the various attributes of the rate design and structure of a Legacy Debt Rider (logically, of course, because that evidence cannot be created when neither the existence, amount or means of repayment of Legacy Debt have been established by the Title III Court), PREB cannot claim to have “checked the box” of holding an evidentiary hearing by relying on the inadequate record in this rate case. These missing pieces include, without limitation: (i) the amount and treatment of

Legacy Debt to be repaid,<sup>40</sup> as determined exclusively within PREPA's Title III Case; (ii) the attributes, characteristics, applicability, and exemptions from such a Legacy Debt Rider; (iii) the repayment period and whether the monthly recovery from ratepayers changes over time; (iv) true-ups, resets, or reconciliations; and (v) allocations across customer classes, e.g., residential (both subsidized and not), commercial, and industrial customers. Arguably, the most concrete evidence in the record about how a Legacy Debt Rider should be designed and structured by PREB originated from Mr. Shannon—but was nothing more than conceptual theory rather than an actionable (or challengeable, for that matter) proposal:

[QUESTION]

But you **don't make any recommendation about what percentage or piece or component should be variable and which percentage or piece or component should be fixed.** Do I have that right?

MR. SAM SHANNON:

That's **correct.**"

12/16 Tr. 267:4-10 (emphasis added).

Finally, and perfectly punctuating the impossibility of PREB lawfully implementing a Legacy Debt Rider on this evidentiary record, Mr. Shannon confirmed—in the following exchange with the Hearing Examiner—that virtually every aspect of the Legacy Debt Rider was tentative and in flux:

MR. SAM SHANNON:

**[S]ince the amount of legacy debt** has not been established, **since all the other things have not been clarified around this.** This is just meant to be a placeholder schedule. **Whatever the Bureau decides,** we would, you know, update and file a tariff sheet in compliance with the Bureau's **ultimate decision on how the rate structure should be.**

*Id.* 98:20-99:4 (emphasis added).

MR. SCOTT HEMPLING:

Mr. Shannon, what I understood was your **intent in putting this piece of paper here was not a heck of a lot more than just putting a piece of paper here, which on which possibly every single word would have to be changed when more facts arose.** Is that correct?

MR. SAM SHANNON:

Yes.

MR. SCOTT HEMPLING:

**So there's no word on this document that purports to be of any real practical use to the future at this point?**

MR. SAM SHANNON:

That's **correct.** It's purely to establish the tariff in the context of a rate case.

---

<sup>40</sup> 12/9 Tr. 399:7-15 ("DR. SUSAN TIERNEY: ... I have not suggested an amount be put into that.").

MR. SCOTT HEMPLING:

I mean, if this document were sitting here and all it said under the word applicable was player to be named later, would that make much of a difference to you in terms of your intent of putting this thing here?

MR. SAM SHANNON

No.

*Id.* 265:14-266:11 (emphasis added). This makes the Legacy Debt Rider that Mr. Shannon (who, again, was retained by LUMA) proposed within this rate case meaningless because it rests, at best, on shifting sands that provide no foundation for PREB’s implementation of such a rider.

#### IV. CONCLUSION

The record does not contain the “complete” and “substantial” evidence about a Legacy Debt Rider, which is required under Puerto Rico law. Therefore, the Committee’s position is that **no** Legacy Debt Rider can or should be implemented now as part of this rate case.

Consistent with rate setting principles and the approach that has been employed by regulators in analogous situations of a pending bankruptcy case (and as observed by PREB’s own consultants), the Commissioners should wait until the Title III Court has determined the amount and treatment of PREPA’s Legacy Debt before any such rider can be appropriately considered by PREB. Finally, if PREB—nevertheless—proceeds to consider some form of a Legacy Debt Rider as part of this rate, any such Legacy Debt Rider must (a) consider and include the total amount of PREPA’s Legacy Debt, including the total amount of General Unsecured Claims filed in PREPA’s Title III Case, and (b) fully preserve the rights of all holders of allowed General Unsecured Claims against PREPA to benefit from any funds collected thereunder.

**Respectfully submitted** on February 17, 2026.

**Certificate of Service:** We hereby certify that, on this date, we have filed this motion through the online filing system of the PREB and sent a copy<sup>41</sup> to the **PREB Clerk:** secretaria@energia.pr.gov, secretaria@jrsp.pr.gov, legal@jrsp.pr.gov, sseda@jrsp.pr.gov; to the *Hearing Examiner* Scott Hempling: shempling@scotthemplinglaw.com; and to all:

**Parties and Intervenors:**

mvalle@gmlex.net; alexis.rivera@prepa.pr.gov; jmartinez@gmlex.net; jgonzalez@gmlex.net; nzayas@gmlex.net; Gerard.Gil@ankura.com; Jorge.SanMiguel@ankura.com; Lucas.Porter@ankura.com; mdiconza@omm.com; golivera@omm.com; pfriedman@omm.com; msyassin@omm.com; katuska.bolanos-lugo@us.dlapiper.com; Yahaira.delarosa@us.dlapiper.com; margarita.mercado@us.dlapiper.com; carolyn.clarkin@us.dlapiper.com; andrea.chambers@us.dlapiper.com; regulatory@genera-pr.com; legal@genera-pr.com; mvazquez@vvlawpr.com; gvilanova@vvlawpr.com; dbilloch@vvlawpr.com; ratecase@genera-pr.com; jfr@sbgblaw.com; hriviera@jrsp.pr.gov; gerardo\_cosme@solartekpr.net; contratistas@jrsp.pr.gov; victorluisgonzalez@yahoo.com; Cfl@mcvpr.com; nancy@emmanuelli.law; jrinconlopez@guidehouse.com;

---

<sup>41</sup> This service list conforms to the email from Ms. Sonia Seda Gaztambide dated February 6, 2026.

Josh.Llamas@fticonsulting.com; Anu.Sen@fticonsulting.com; Ellen.Smith@fticonsulting.com;  
 Intisarul.Islam@weil.com; alexis.ramsey@weil.com; kara.smith@weil.com;  
 rafael.ortiz.mendoza@gmail.com; rolando@emmanuelli.law; monica@emmanuelli.law;  
 cristian@emmanuelli.law; luis@emmanuelli.law; jan.albinolopez@us.dlapiper.com;  
 Rachel.Albanese@us.dlapiper.com; varoon.sachdev@whitecase.com; javrua@sesapr.org;  
 Brett.ingerman@us.dlapiper.com; brett.solberg@us.dlapiper.com; agraitfe@agraitlawpr.com;  
 jpouroman@outlook.com; epo@amgprlaw.com; loliver@amgprlaw.com;  
 acasellas@amgprlaw.com; matt.barr@weil.com; Robert.berezin@weil.com;  
 Gabriel.morgan@weil.com; corey.brady@weil.com; lindsay.greenbaum@analysisgroup.com;  
 harrison.holtz@analysisgroup.com; charles.wu@analysisgroup.com;  
 Brian.Gorin@analysisgroup.com; Bhumika.Sharma@analysisgroup.com;  
 Rachel.Anderson@analysisgroup.com; lramos@ramoscruzlegal.com; tlauria@whitecase.com;  
 gkurtz@whitecase.com; ccolumbres@whitecase.com; isaac.glassman@whitecase.com;  
 tmacwright@whitecase.com; jcunningham@whitecase.com; mshepherd@whitecase.com;  
 jgreen@whitecase.com; hburgos@cabprlaw.com; dperez@cabprlaw.com;  
 howard.hawkins@cwt.com; mark.ellenberg@cwt.com; casey.servais@cwt.com;  
 bill.natbony@cwt.com; zack.schrieber@cwt.com; thomas.curtin@cwt.com;  
 escalera@reichardescalera.com; riverac@reichardescalera.com;  
 susheelkirpalani@quinnemanuel.com; erickay@quinnemanuel.com;  
 dmonserrate@msglawpr.com; fgierbolini@msglawpr.com; rschell@msglawpr.com;  
 eric.brunstad@dechert.com; Stephen.zide@dechert.com; David.herman@dechert.com;  
 Isaac.Stevens@dechert.com; James.Moser@dechert.com; michael.doluisio@dechert.com;  
 Kayla.Yoon@dechert.com; mfb@tcm.law; lft@tcm.law; arosenberg@paulweiss.com;  
 pbrachman@paulweiss.com; swintner@paulweiss.com; kzeituni@paulweiss.com;  
 Julia@londoneconomics.com; Brian@londoneconomics.com; luke@londoneconomics.com;  
 juan@londoneconomics.com; mmc Gill@gibsondunn.com; LShelfer@gibsondunn.com;  
 jcasillas@cstlawpr.com; jnieves@cstlawpr.com; pedrojimenez@paulhastings.com;  
 ericstolze@paulhastings.com; arrivera@nuenergypr.com; apc@mcvpr.com;  
 ramonluisnieves@rlnlegal.com; kbailey@acciongroup.com; and

#### **PREB Consultants:**

rsmithla@aol.com; guy@maxetaenergy.com; jorge@maxetaenergy.com;  
 rafael@maxetaenergy.com; dawn.bisdorf@gmail.com; msdady@gmail.com;  
 mcranston29@gmail.com; ahopkins@synapse-energy.com; clane@synapse-energy.com;  
 kbailey@acciongroup.com; zachary.ming@ethree.com; PREBconsultants@acciongroup.com;  
 carl.pechman@keylogic.com; bernard.neenan@keylogic.com; tara.hamilton@ethree.com;  
 aryeh.goldparker@ethree.com; roger@maxetaenergy.com; Shadi@acciongroup.com;  
 MWhited@synapse-energy.com.

#### *Counsel for the Committee*

##### **PAUL HASTINGS LLP**

/s/ Pedro A. Jimenez

Pedro A. Jimenez, Esq. (*Pro Hac Vice*)

200 Park Ave.

New York, NY 10166

pedrojimenez@paulhastings.com

Tel.: (212) 318-6970

Fax: (212) 319-4090

/s/ Eric D. Stolze

Eric D. Stolze, Esq. (*Pro Hac Vice*)

1197 Peachtree St., N.E., Ste. 200

Atlanta, GA 30361

ericstolze@paulhastings.com

Tel.: (404) 815-2315

Fax: (404) 685-5315

#### *Local Counsel for the Committee*



PO Box 195075

San Juan, PR 00919-5075

Tel.: (787) 523-3434

Fax: (787) 523-3433

jcasillas@cstlawpr.com

jnieves@cstlawpr.com

**s/JUAN J. CASILLAS AYALA**

RUA Num.: 12145

**s/JUAN C. NIEVES GONZÁLEZ**

RUA Num.: 19087

**ADDENDUM TABLE OF CONTENTS**

|                                                                                                                                                                                                                                                                                                                                            | <b>Add.</b> |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------|
| Email from LUMA’s Counsel to Committee’s Counsel (Nov. 20, 2025) .....                                                                                                                                                                                                                                                                     | 1           |
| New Orleans City Council, R-06-459, <i>Resolution and Order Approving Agreement in Principle</i><br>(Oct. 27, 2006) .....                                                                                                                                                                                                                  | 2           |
| California Public Utilities Commission, <i>Decision Approving Reorganization Plan</i><br>(May 28, 2020).....                                                                                                                                                                                                                               | 3           |
| California Public Utilities Commission, <i>Decision Approving Imposition of a Non-Bypassable<br/>Charge to Support California's Wildfire Fund and Adopting Rate Agreement Between The<br/>California Department of Water Resources and the California Public Utilities Commis[si]on,</i><br>Rule No. 19-07-017, at 6 (Oct. 24, 2019) ..... | 4           |

# Addendum 1

**From:** Bolanos-Lugo, Katuska  
**To:** Jimenez, Pedro; Stolze, Eric D.; jcasillas@cstlawpr.com; jnieves@cstlawpr.com  
**Cc:** Mercado, Margarita; DelaRosa, Yahaira; Chambers, Andrea; Solberg, Brett; Albinolopez, Jan  
**Subject:** [EXT] OCUCP-of-LUMA-RR  
**Date:** Thursday, November 20, 2025 8:04:36 PM  
**Attachments:** image001.png

-- External Email --

[Report Suspicious](#)

Colleagues,

LUMA is currently responding to over 100 ROIs, including those submitted by the Committee. However, upon review, LUMA has identified that certain information requested is not within its possession, was provided solely by PREPA and PREPA is the only party in possession of responsive information. These items are listed in the table below.

LUMA will respond, for the record, that this information is not available to it, but we are providing this notice in advance.

Wishing you a good night,

Katuska

|                            |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
|----------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>OCUCP-of-LUMA-RR-86</b> | Please confirm no scenario within Schedule B-3 accounts for general unsecured claims that have been asserted against PREPA in its Title III Case. Alternatively, if you contend that schedule B-3 accounts for general unsecured claims within PREPA's Title III Case, then please: (i) identify the total amount of general unsecured claims within each of the scenarios within Schedule B-3; (ii) specify the dollar amount of the "Total Low," Total High," and "Subtotal Title" within each of the scenarios within Schedule B-3 that is attributable to or on account of general unsecured claims within PREPA's Title III Case; and (iii) explain how the amounts within (i) and (ii) above were calculated.                                                                                                                                                                                                        |
| <b>OCUCP-of-LUMA-RR-87</b> | Please confirm no scenario within Schedule B-3 accounts for any payment to the holders of general unsecured claims within PREPA's Title III Case, as contemplated within the "Fifth Amended Plan of Adjustment and Disclosure Statement" (as referred to within Note 1 of Schedule B-3).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| <b>OCUCP-of-LUMA-RR-88</b> | Please provide and explain all reason(s), rationale(s), and justification(s) for including each of the following (and the subcomponents within it) within each the scenarios within Schedule B-3, including all bases for contrasting each of the following with general unsecured claims within PREPA's Title III Case: (i) "Fuel Lines"; (ii) "Legacy Bonds"; (iii) "Series A Bonds in Aggregate: Expected Cash Flows"; (iv) Series B Bonds in Aggregate: Expected Cash Flows"; (v) "Series A & B Expected Cash Flows"; (vi) "Pension Obligation." As used within this ROI, "subcomponents" means each indented line item underneath the quoted heading appearing in bold text on Schedule B-3, e.g., "(vi) Pension Obligation" above requests a discrete response as to each of the following, individual items: (x) "Pension Obligation"; (y) "PAYGO Funding for PREPA ERS"; and (z) "Retiree Medical Benefits (OPEB). |
| <b>OCUCP-of-LUMA-RR-89</b> | Please confirm no scenario within Schedule B-4 accounts for general unsecured claims that have been asserted against PREPA in its Title III Case. Alternatively, if you contend that schedule B-4 accounts for general unsecured claims within PREPA's Title III Case, then please: (i) identify the total amount of general unsecured claims within each of the four scenarios within Schedule B-4; (ii) specify the dollar amount of the "Total Debt Service" within each of the four scenarios that is attributable to or on account of general unsecured claims within PREPA's Title III Case; and (iii) explain how the amounts within (i) and (ii) above were calculated.                                                                                                                                                                                                                                            |
| <b>OCUCP-of-LUMA-RR-90</b> | Please explain how "Total Debt Service" within each of the four scenarios within Schedule B-4 was calculated, including: (i) how the amount of interest or other fees on account of a principal balance was derived; and (ii) how the amount of principal paid as part of any debt service payment was derived.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| <b>OCUCP-of-LUMA-RR-91</b> | Please list (identifying with specificity) or provide in response to this ROI all documents that you reviewed, considered, or relied upon in creating Schedule B-3 or Schedule B-4 and, for each document, explain how it was used (if at all).                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |

Katuska Bolanos

Of Counsel

T +1 787 945 9139  
F +1 939 697 6169  
M +1 787 458 8276  
katuska.bolanos-lugo@us.dlapiper.com

DLA Piper (Puerto Rico) LLC  
500 Calle de la Tanca, Suite 401  
San Juan, PR 00901-1969



[dlapiper.com](https://dlapiper.com)

The information contained in this email may be confidential and/or legally privileged. It has been sent for the sole use of the intended recipient(s). If the reader of this message is not an intended recipient, you are hereby notified that any unauthorized review, use, disclosure, dissemination, distribution, or copying of this communication, or any of its contents, is strictly prohibited. If you have received this communication in error, please reply to the sender and destroy all copies of the message. Do not contact us directly, send to postmaster@dlapiper.com. Thank you.

# Addendum 2

**RESOLUTION  
R-06-459**

**CITY HALL: OCTOBER 27, 2006**

**BY: COUNCILMEMBERS THOMAS, HEDGE-MORRELL, MIDURA, AND CARTER**

**IN THE MATTER OF APPLICATION OF ENTERGY NEW ORLEANS, INC.  
FOR APPROVAL OF IMPLEMENTATION OF  
POST-KATRINA GAS AND ELECTRIC FORMULA RATE PLANS,  
DOCKET NOS. UD-01-04 AND UD-03-01**

**And**

**IN THE MATTER OF APPLICATION OF ENTERGY NEW ORLEANS, INC.  
FOR AUTHORIZATION TO IMPLEMENT RIDERS TO RECOVER  
COSTS RELATED TO HURRICANES KATRINA AND RITA (DOCKET NO. UD-06-01)  
AND TO ADEQUATELY FUND A STORM RESERVE (DOCKET NO. UD-06-02)**

**RESOLUTION AND ORDER APPROVING AGREEMENT IN PRINCIPLE**

**WHEREAS**, pursuant to the Constitution of the State of Louisiana and the Home Rule Charter of the City of New Orleans ("Charter"), the Council of the City of New Orleans ("Council") is the governmental body with the power of supervision, regulation and control over public utilities providing service within the City of New Orleans; and

**WHEREAS**, pursuant to its powers of supervision, regulation and control over public utilities, the Council is responsible for fixing and changing rates and charges of public utilities and making all necessary rules and regulations to govern applications for the fixing and changing of rates and charges of public utilities; and

**WHEREAS**, Entergy New Orleans ("ENO" or "Company") is a public utility providing electric service to all of New Orleans, except the Fifteenth Ward ("Algiers"), and gas service to all of New Orleans; and

**WHEREAS**, in Resolution R-03-272, adopted by the Council on May 15, 2003, the Council approved an electric formula rate plan ("EFRP") and a gas formula rate plan ("GFRP") (collectively, "FRPs") for ENO; and

**WHEREAS**, in Resolution R-05-512 (authorized by letter of the Chairman of the Council Utility, Cable and Telecommunications Committee, dated August 31, 2005, and deemed by Resolution R-05-U4 to be effective as of September 1, 2006), the Council extended ENO's FRPs for the years 2006 and 2007 and approved certain modifications to the FRPs; and

**WHEREAS**, the FRPs are now embodied in ENO's Electric Formula Rate Plan Rider Schedule ("Rider Schedule EFRP-2") and Gas Formula Rate Plan Rider Schedule ("Rider Schedule GFRP-2"), respectively, filed with the Council; and

**WHEREAS**, pursuant to Section II.B.1 of Rider Schedules EFRP-2 and GFRP-2, ENO is required to file reports with the Council on or before May 1 of each year containing evaluations of ENO's earnings for the immediately preceding calendar year for its electric and gas operations, respectively, in accordance with the provisions of Section II.C of such rider schedules; and

**WHEREAS**, such evaluations are to be conducted with respect to a midpoint return on equity ("ROE") of 10.75%, a targeted equity ratio of 45 percent and a "dead band" range, or "bandwidth," around such midpoint ROE for each of the EFRP and the GFRP; the ROE bandwidth for the EFRP is +/- 100 basis points from the midpoint ROE and the ROE bandwidth for the GFRP is zero (0) basis points from the midpoint ROE for the 2005 Evaluation Period and +/- 50 basis points for the 2006 Evaluation Period; actual rates of return earned during the Evaluation Period falling within the bandwidth would result in no change to ENO's base rates;

actual rates of return falling above or below the bandwidth would result in prospective adjustments to ENO's base rates downward or upward, respectively; and

**WHEREAS**, as we noted in Resolution R-03-272, designating a midpoint ROE for ENO's electric and gas FRPs is consistent with the Council's obligation to authorize rates for ENO that are just and reasonable. The United States Supreme Court cases Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) require utility regulators to authorize a rate of return on common equity that will (1) fairly compensate capital invested in the utility; (2) enable the utility to offer a return adequate to attract new capital on reasonable terms; and (3) maintain the utility's financial health; and

**WHEREAS**, on August 29, 2005, Hurricane Katrina struck the City of New Orleans. The hurricane and ensuing multiple levee failures caused widespread flooding throughout the City, endangering the lives and health of thousands of New Orleanians and causing catastrophic damage to homes, businesses and infrastructure. New Orleans was subject to mandatory evacuation, and the flooding and pervasive damage rendered the City uninhabitable and prohibited residents from returning to their homes for months afterwards. The devastation caused by Hurricane Katrina is considered to be the worst natural disaster in U.S. history; and

**WHEREAS**, as a result of Hurricane Katrina and the levee failures, ENO suffered severe damage to its electric and gas utility<sup>o</sup>systems and, with the exodus of residents from the City, experienced dramatic reductions in its customer base and, accordingly, its base rate revenues; and

**WHEREAS**, on September 23, 2005, largely as a result of the extensive damage to its utility infrastructure and loss of customers and revenues, ENO filed a voluntary petition in the

United States Bankruptcy Court for the Eastern District of Louisiana seeking reorganization relief under the provisions of the Chapter 11 of the United States Bankruptcy Code; and

**WHEREAS**, ENO, to this day, operates as a debtor-in-possession subject to the jurisdiction of the Bankruptcy Court; and

**WHEREAS**, on April 20, 2006, the Council in Resolution R-06-167, extended ENO's deadline to file its 2006 FRP reports to July 1, 2006 and similarly extended all related procedural deadlines set forth in Rider Schedules EFRP-2 and GFRP-2 by 61 days; and

**WHEREAS**, on June 30, 2006, ENO filed with the Council its *Application of Entergy New Orleans, Inc. for Approval of Implementation of Post-Katrina Gas and Electric Formula Rate Plans* ("FRP Application") in Docket Nos. UD-01-04 and UD-03-01; and

**WHEREAS**, in its FRP Application, ENO seeks authorization from the Council to increase its electric and gas base rates based upon the Electric and Gas FRPs approved by the Council on September 2, 2005, "as adjusted for the significant loss of ENO's customers following the August 29, 2005 landfall of Hurricane Katrina and recovery of [the costs of ENO's share of the] Grand Gulf [nuclear plant] in ENO's Fuel Adjustment Clause"; and

**WHEREAS**, ENO's Electric FRP filing consists of three Evaluation Reports, each under a separate volume, as follows: 1) a "Business as Usual" report filed under the FRP formula; 2) a report containing a "post-Katrina revenue adjustment for loss of customers" and the removal of the nonfuel costs of Grand Gulf from base rates for recovery in ENO's monthly Fuel Adjustment Clause ("FAC"); and 3) a report containing the post-Katrina revenue adjustment for loss of customers and Grand Gulf non-fuel costs recovered in base rates; and

**WHEREAS**, ENO specifically requests that the Council approve its second Electric Evaluation Report containing the revenue adjustment for loss of customers and removal of Grand

Gulf costs from base rates for recovery in the FAC. The second Evaluation Report results in a base rate revenue increase of \$6.381 million, as well as recovery of Grand Gulf non-fuel costs (approximately \$90.625 million per year) in the FAC. ENO's filing indicates that such a base rate increase resulting from the second Electric Evaluation Report would increase typical summer electric residential bills (1000 kWh), based on the June 2006 FAC, from \$115.18 to \$118.09, a net increase of \$2.91, and provide increases to the other electric customer classes; and

**WHEREAS**, ENO's Gas FRP filing consists of two Evaluation Reports, each under a separate volume, as follows: 1) Business as Usual; and 2) Post-Katrina revenue adjustment for loss of customers; and

**WHEREAS**, ENO similarly requests that the Council approve its second Gas Evaluation Report containing the revenue adjustment for loss of customers. The second Evaluation Report results in a gas base rate revenue increase of \$22.844 million. ENO's filing indicates that such a base rate increase resulting from the second Gas Evaluation Report would increase typical gas residential bills (50 ccf), based on the June 2006 PGA, from \$62.40 to \$89.03, a net increase of \$26.63, and provide increases to the other gas customer classes; and

**WHEREAS**, on June 30, 2006, ENO also filed with the Council its *Application of Entergy New Orleans for Authorization to Implement Riders to Recover Costs Related to Hurricanes Katrina and Rita and to Adequately Fund a Storm Reserve* ("Rider Application"); and

**WHEREAS**, in its Rider Application, ENO requests authorization to implement two riders to electric and gas bills that would become effective on or after the first billing cycle of November 2006. In connection with the first rider, the Storm Cost Recovery Rider, ENO seeks authorization to recover over a ten-year period \$124.829 million of costs of gas and electric

restoration work performed and recorded on the Company's books through March 31, 2006 associated with Hurricane Katrina (and the subsequent Hurricane Rita), as well as the write-off for uncollectible expenses of \$14.627 million, for a total recovery of \$139.456 million. In connection with the second rider, the Storm Reserve Rider, ENO seeks authorization to fund over a ten-year period a pre-tax amount of \$150 million for a dedicated storm reserve that will be available and adequate to pay for resources required for ENO to recover from future storms; and

**WHEREAS**, the Advisors and all Intervenors in Docket UD-01-04 received a copy of each of ENO's FRP Application and Rider Application together with workpapers supporting the data and calculations reflected in these filings; and

**WHEREAS**, on August 3, 2006, the Council adopted Resolution R-06-329 establishing procedures for the consideration of ENO's FRP Application and Rider Application; and

**WHEREAS**, the Council found in Resolution R-06-329 that the ENO's FRP applications are annual filings required of ENO in accordance with settlement agreements arrived at among the Council, ENO and the parties to Dockets UD-01-04 and UD-03-01, and that ENO's rider requests are separate requests for enhanced rates by ENO based on costs and projections that are being presented to the Council for the first time. Accordingly, the Council established separate dockets for its consideration of ENO's FRP Application and rider requests with consideration of the FRP Application to occur in Docket Nos. UD-01-04 and UD-03-01, consideration of the Storm Cost Recovery Riders to occur in Docket No. UD-06-01 and consideration of ENO's Storm Reserve Riders to occur in Docket No. UD-06-02; and

**WHEREAS**, Resolution R-06-329 also (1) addressed the continued designation and appointment of the Honorable Jeffrey Gulin as Hearing Officer; (2) established an intervention period of ten (10) days from the date of the adoption of Resolution R-06-329 for potential

intervenors, noting that the original Intervenor in Docket Nos. UD-01-04 and UD-03-01 were deemed Intervenor and Parties for the purpose of reviewing ENO's FRP Filings; (3) confirmed that the procedural schedule for consideration of the FRP Filings would be consistent with the 61-day extension granted in Resolution R-06-167; (4) established separate procedural schedules for ENO's Storm Cost Recovery Riders and Storm Reserve Riders; and (5) established rules governing the discovery process and the filing of pleadings, testimony, comments and briefs for each of ENO's filings; and

**WHEREAS**, pursuant to Resolution R-06-329 and the FRP Rider Schedules, several of the parties in this proceeding served numerous discovery requests on ENO including the Advisors, which alone, propounded more than 200 discovery requests on the Company; and

**WHEREAS**, on September 21, 2006, as provided for in Rider Schedule EFRP-2 and Rider Schedule GFRP-2 and Resolution R-06-329, the Advisors, the New Orleans Sewerage and Water Board ("S&WB"), the New Orleans Business Energy Council ("NOBEC"), Air Products and Chemicals, Inc. (Air Products") and the Alliance for Affordable Energy ("Alliance") submitted reports, identifying asserted errors in the application of the principles and procedures contained in Rider Schedule EFRP-2 and Rider Schedule GFRP-2 to ENO's FRP Application and proposed regulatory adjustments required to develop just and reasonable rates; and

**WHEREAS**, in March 2006, ENO filed with the Louisiana Recovery Authority ("LRA") a draft application wherein ENO requested from the LRA an allocation of \$718 million to pay for costs ENO incurred in connection with Hurricane Katrina including the costs of repair and replacement of facilities damaged during the storm and certain unrecovered fixed costs and, on September 6, 2006, ENO revised its request to seek an allocation of \$592 million; and

**WHEREAS**, on September 13, 2006, a letter, executed by all seven members of this Council, was sent to the LRA strongly urging the LRA to act favorably on ENO's request for CDBG funds and indicating that the LRA's decision was crucial to the Council's decision on ENO's pending FRP Application; and

**WHEREAS**, in its letter, the Council also specified seven conditions which it indicated should be agreed to by ENO in connection with any CDBG funds ENO may receive, indicating that "[w]ith these conditions in place, the interests of the citizens and ratepayers of New Orleans will be protected and their financial burdens reduced;" and

**WHEREAS**, on October 12, 2006, the LRA adopted a resolution granting to ENO \$200 million of CDBG funds, wherein the LRA expressly adopted six of the Council's conditions and required ENO to comply with them; and

**WHEREAS**, ENO agreed to these conditions during the course of the LRA's proceedings; and

**WHEREAS**, the LRA, in its resolution, also pledged to "work with the Governor, the Louisiana Congressional Delegation, the City of New Orleans, and ENO, to petition the President of the United States and the United States Congress for additional federal funds to cover future gas system repair costs which are largely due to salt water intrusion that resulted from the failure of the federal government's levee system;" and

**WHEREAS**, in the rate proceeding before the Council, ENO, the Advisors and the Intervenors, following submission of the various parties' reports concerning ENO's FRP requests, commenced a series of confidential settlement negotiations intended to resolve discrepancies or disputes arising from ENO's FRP Application, as well as issues related to ENO's Rider Application; and

**WHEREAS**, these negotiations have lead to the development of an Agreement in Principle which is supported or not opposed by ENO, the Council's Advisors, S&WB, NOBEC, Air Products and the Alliance; and

**WHEREAS**, ENO filed the Agreement in Principle with the Council on October 27, 2006; and

**WHEREAS**, a copy of the Agreement in Principle is appended hereto as Attachment A; and

**WHEREAS**, a brief overview of the principal terms and conditions of Agreement in Principle are provided in this paragraph. The Agreement in Principle itself should be consulted for a full and complete understanding of the rights and obligations contained therein.

**Electric Rates and Charges**

1. Electric base rates will remain unchanged through December 2007.
2. Electric base rates will be increased by \$3.9 million effective with the first billing cycle of January 2008.
3. Grand Gulf non-fuel costs will be removed from electric base rates and collected in the FAC.
4. Rates for the LIS class will be treated separately as provided in the Agreement in Principle.

**Gas Rates and Charges**

5. Gas base rates will be increased by \$4.75 million effective with the first billing cycle of November 2006.
6. Gas base rates will be increased by an additional \$4.75 million effective with the first billing cycle of November 2007.

7. ENO will increase the monthly customer charge for residential gas service from \$6.20 to \$8.00 and increase the customer charge for small general gas service and small municipal gas service from \$4.08 to \$8.00 per month, effective with the first billing cycle of March 2007..

#### **Future Rate Procedures**

8. On or before July 31, 2008, ENO will file a base rate case using the 12 months ended December 2007 as the Period I test year and the 12 months ended December 2008 as the Period II test year.
9. In connection with the ENO base rate case, ENO will conduct studies pertaining to appropriate post-Katrina service levels and costs, cost allocation and rate design, accounting treatments, customer service charges and depreciation.
10. Under very limited circumstances, such as another natural disaster, ENO will have the right to file for emergency rate relief prior to the aforementioned base rate case.
11. ENO may seek Council approval of appropriate electric and gas formula rate plan mechanisms after six months from the effective date of the implementation of the base rates resulting from the base rate case.

#### **Generation Resource**

12. ENO will seek to obtain an energy-only, "load shaped" generation resource of approximately 50 MW for service to ENO consumers.

#### **Storm Cost Recovery Rider**

13. Subject to the results of the audit of ENO's storm costs being conducted by the Council's Advisors and assuming ENO's timely receipt of CDBG funds, ENO will apply the CDBG funds to its uncollectible amounts, deferred O&M amounts and/or capital rate

base items. Any CDBG funds remaining after application of such funds to offset ENO's deferred storm costs incurred through March 31, 2006, shall be applied to offset additional certified costs as audited by the Council's Auditors.

14. Procedures for the accounting for storm costs and addressing storm costs incurred in excess of CDBG funding are established.
15. If by September 1, 2007, CDBG funding has not materialized in an amount that significantly mitigates ENO's storm cost recovery request for costs incurred through March 31, 2006, ENO may file for emergency rate relief.
16. Insurance proceeds received by ENO also shall be used to offset its storm related costs.
17. ENO will file with the Council by July 1, 2007, a plan of reconstruction for its damaged gas system that includes identification of relevant priorities and contingencies.

#### **Storm Reserve Rider**

18. ENO will be permitted to implement a Storm Reserve Rider to fund a storm reserve principal amount of \$75 million over ten years.
19. ENO commits to work jointly with the Council in seeking an exception to the Stafford Act in Congress that will afford ENO Stafford Act protections in the event of another catastrophic event that adversely affects its gas and electric systems during the next ten years. To the extent that the Stafford Act effort is successful, the Storm Reserve Rider may be reduced or eliminated after holding a full and fair hearing.
20. The storm reserve fund is to be accorded "lock box" treatment and will be held in a escrow account as dedicated ratepayer funds and may be used only for restoration of utility service following a storm causing a minimum of \$500,000 damage and may not be used for any other corporate purpose.

21. After five years, the Council may reconsider the level of the storm reserve and adjust the level of future funding prospectively.

#### **Energy Conservation and Energy Efficiency Programs**

22. ENO is committed to working actively with the Council's Advisors, the City Council, and the community to develop effective and appropriate energy conservation and energy efficiency programs in the New Orleans community reflective of the community's post-Katrina needs.
23. To the extent ENO's storm-related uncollectible expenses have been offset as previously authorized by the Council, are deemed eligible for CDBG funds and are certified and reimbursed with CDBG funds, ENO shall make available up to \$6.9 million of such funds for post-Katrina energy conservation and energy efficiency programs in the New Orleans community as authorized by the City Council.

#### **Plan of Reorganization**

24. To the extent that ENO issues notes in connection with affiliate pre-petition obligations, such notes shall not be reflected in ENO's retail rates, as provided for in the Agreement in Principle.

**WHEREAS**, the Agreement in Principle is expressly contingent on, among other things, ENO obtaining approval of its Board of Directors and the Council adopting a resolution approving the Agreement in Principle; and

**WHEREAS**, on October 27, 2006, the Council received from ENO written approval of its Board of Directors of the Agreement in Principle; and

**WHEREAS**, the Council wishes to commend ENO, SW&B, NOBEC, Air Products, the Alliance and the Council's Advisors for their efforts to devise this settlement of these important rate proceedings; and

**WHEREAS**, on the basis of the record before the Council and the support or non-opposition of all the active Intervenors in the FRP process for acceptance of the Agreement In Principle and for the reasons set forth below, the Council wishes to approve this Agreement in Principle; now, therefore:

**BE IT RESOLVED BY THE COUNCIL OF THE CITY OF NEW ORLEANS**

**THAT:**

The Agreement In Principle submitted by ENO on October 27, 2006 in Docket Nos. UD-01-04, UD-03-01, UD-06-01 and UD-06-02 and supported or not opposed by the Council's Advisors, NOBEC, S&WB, Air Products and the Alliance, is determined on the basis of the record before us to be just, reasonable, and in the public interest. Accordingly, the Agreement In Principle is approved without modification. The Agreement In Principle is determined to be reasonable and in the public interest for the following reasons.

**Rate Benefits**

The Agreement in Principle will provide significant rate benefits to New Orleans ratepayers. These benefits will take several forms.

First, electric and gas base rates will not be increased as much as sought by the Company in its FRP Application. In its application, ENO proposed to recover Grand Gulf non-fuel costs in the FAC and to increase electric base rates by an amount equal to \$6.8 million, or 4.4% (when adjusted to apply over the rate effective period of November 2006 to October 2007). The Agreement in Principle, while allowing ENO to collect Grand Gulf non-fuel costs in the FAC,

eliminates any base rate increase for over one year and provides for a base rate increase of only \$3.9 million, or 2.5%, beginning with the first billing cycle in January 2008. Similarly, with respect to gas base rates, ENO's request, when applied over the same period, would have resulted in an increase in gas base rates of \$29.1 million, or 160.9%. The Agreement in Principle reduces this increase significantly to \$4.75 million, or 26.3%, beginning in November 2006, followed by an increase in ENO's customer charges in March 2007 that is equivalent to \$1.5 million, or 8.3%, and a second base rate increase beginning in November 2007 of \$4.75 million, or 26.3%. These reductions in the requested base rate increases represent substantial savings to New Orleans ratepayers.

Second, the Agreement in Principle eliminates ENO's proposed Storm Cost Recovery Rider. In its Rider Application, ENO proposed to add to ratepayers bills a rider to collect the costs it incurred as a result of Hurricanes Katrina and Rita. Those costs amounted to \$139.5 million as of March 31, 2006. ENO proposed to amortize these costs over ten years. Such amortization would produce a revenue requirement of \$14.7 million per year for electric operations and \$3.7 million for gas operations, for a total of \$18.4 million. In response to the grant of CDBG funds to ENO by the Louisiana Recovery Authority on October 12, 2006, the Agreement in Principle directs that such CDBG funds will be used to offset ENO's storm costs on a dollar-for-dollar basis. This offset enables ENO to recover its storm costs without imposing the Storm Cost Recovery Rider. The elimination of this rider inures directly to the benefit of ratepayers.

Third, the Agreement in Principle greatly reduces the Storm Reserve Rider charges ENO sought in its Rider Application. ENO had proposed ratepayer funding of a reserve of \$150 million over ten years, which would have resulted in charges of \$11.3 million per year to electric

customers and \$1.7 million per year to gas customers, for a total of \$13.0 million per year. The Agreement in Principle reduces the reserve to \$75 million and, thus, reduces the rider charges to \$5.8 million per year for electric customers and \$650 thousand per year for gas customers.

Fourth, as a result of these reductions, ratepayers will avoid a significant portion of the increases in their total bills that would have resulted from the Company's original requests. In its filings, ENO proposed FRP and rider increases which together would increase typical residential electric bills by \$11.90, or 9.6 %, and typical residential gas bills by \$32.96, or 57.0%. In contrast, the Agreement in Principle results in initial increases to typical residential electric bills of \$0.00, or 0.0%, and typical residential gas bills of \$4.35, or 7.5%. When all the stepped increases in the Agreement in Principle are implemented (January 2008 for electric operations and November 2007 for gas operations), typical residential electric bills will be increased by \$3.36, or 2.7% , and typical residential gas bills will be increased by \$9.79, or 16.9%.

These bill increases are far below those that were forecast in the media to occur following Katrina. Projections of ratepayers seeing increases in their utility bills of 100% or more were made. In fact, there will be rate stability and no catastrophic increases in bills, in part, because ENO did not seek base rate and rider increases that would have resulted in such high bills and, in part, because the Agreement in Principle further reduces the impacts on customer bills.

Fifth, bills for electric service in New Orleans, while somewhat higher than average bills in the South, remain below those of several major southeastern cities. According to the Jacksonville Electric Survey of typical 1000 kWh bills in July 2006, the typical residential bill in New Orleans during that month was \$117.92. Adding the change in bills brought about by ENO's Storm Reserve Rider (\$2.04), and factoring out changes in the FAC that may have

occurred between July and November, would produce a typical residential bill in New Orleans of \$119.96. This compares favorably to bills in several other regional metropolitan areas, including Houston (\$163.20), Dallas (\$153.73) and Tallahassee (\$134.00).

#### **ENO Financial Condition**

A fundamental premise of our analysis is that the New Orleans community needs a financially sound utility, one that is capable of providing reliable electric and gas service at reasonable prices to New Orleans ratepayers over the long term. New Orleans does not have that today. Rather, ENO has been since September 2005, and continues to be, in bankruptcy as a debtor-in-possession subject to the jurisdiction of the United States Bankruptcy Court.

As a result of ENO's bankruptcy, ENO, for instance, is unable to access the capital markets at reasonable rates to obtain needed financing for its restoration efforts and ongoing capital programs. Similarly, ENO's access to the competitive wholesale power markets has been severely curtailed. ENO has represented that a significant number of power suppliers have refused to deal with ENO, and ENO has been limited in its participation in the Entergy System's joint account purchases. These handicaps can serve to increase ENO's costs of providing service and hinder its efforts to restore its damaged utility systems to their former levels of service and reliability.

The Council believes that the Agreement in Principle represents a critical step toward returning ENO to financial health and permitting it to emerge from bankruptcy. The Agreement in Principle will provide ENO with rate relief for both its electric and gas operations. That relief will be known and fixed from November 2006 through the first quarter of 2009 and, thus, will provide ENO, its creditors and the Bankruptcy Court with a high degree of certainty as to the level of revenues ENO can be expected to receive over this roughly two and one-half year

period. Moreover, the Agreement in Principle sets forth a rational method and known time frame for setting ENO's rates after that three year period on the basis of sound regulatory principles.

The Agreement in Principle also provides ENO with a Storm Reserve. Although the Storm Reserve is not as large as ENO originally sought (\$150 million), it is nevertheless very substantial (\$75 million). The Council believes that, in time, as the Storm Reserve balance accumulates, it will provide assurance to ENO, its creditors and the community that ENO will be better able to survive natural disasters of the kind brought about by Hurricane Katrina, should such disasters occur in the future.

The Agreement in Principle is but one step in the path toward returning ENO to financial health. A major step was taken earlier this month with the award to ENO by the LRA of \$200 million of CDBG funds. Now that the LRA award has been made, all parties must work hard to ensure that those funds are actually paid to ENO in a timely manner.

Another major step in this path to ENO's financial health is the approval of a Plan of Reorganization for ENO by the Bankruptcy Court. Earlier this week, ENO filed such a plan with the court. As the plan is only recently filed, it is premature for the Council to comment on it here. Nevertheless, the Council believes that with the rate relief that will be made available to ENO by virtue of the Agreement in Principle, and the resulting rate and revenue certainty ENO will be afforded for the next three years, ENO's emergence from bankruptcy will be facilitated as this critical element of ENO's financial picture will be known.

### **Generation Resource**

As indicated, the Agreement in Principle provides that ENO shall seek to obtain an incremental generation resource for service to its consumers for the summer of 2007 and

continuing for at least three annual periods. The resource is to be with a low heat rate and be structured to follow ENO's load shape. We believe this resource will provide further benefits to New Orleans ratepayers in that it will provide energy cost savings and serve to stabilize ENO's highly volatile fuel adjustment clause during the summer months. In the landmark 2003 settlement with ENO, ENO provided the City several alternative power supply resources that, through June 2006, produced savings to ratepayers of \$175 million. Although this resource is smaller than the combined resources provided in 2003, the Council expects it to provide significant energy cost savings.

#### **Energy Conservation and Energy Efficiency**

An important policy objective of this Council is to dramatically improve energy conservation and energy efficiency in our City. The Agreement in Principle helps further that objective. In it, ENO commits to working actively with the Council, its Advisors and the community to develop effective and appropriate energy conservation and energy efficiency programs. In addition, ENO will make available up to \$6.9 million of funds for such programs, subject to certain conditions.

#### **Avoidance of Litigation**

The Agreement in Principle is a negotiated resolution of three major proceedings before the Council, each involving large sums of money and important policy issues. Those proceedings presented the very real prospect of extensive litigation before the Council which likely would have been expensive and time-consuming. The Agreement in Principle avoids such litigation and permits the Council, its Advisors and the parties to focus their efforts on other pressing matters concerning the provision of reliable and affordable utility service in New Orleans.

## **Unanimous Agreement**

The Agreement in Principle is supported or not opposed by all the active parties to these proceedings. It reflects the parties' combined wisdom and sense of compromise. The Council wishes to acknowledge and express its gratitude to ENO, SW&B, NOBEC, Air Products, the Alliance and our Advisors for their hard work and good faith efforts which will facilitate long-term reliable electric and gas service at affordable rates for the people of New Orleans.

**BE IT FURTHER RESOLVED** that Docket Nos. UD-01-04 and UD-03-01 are hereby terminated.

**BE IT FURTHER RESOLVED** that Docket No. UD-06-02 is hereby terminated.

**BE IT FURTHER RESOLVED** that ENO is directed to make compliance filings as specified in the Agreement in Principle, and to work with the Council's Advisors to further refine the FAC rate schedule consistent with the objectives of this Agreement in Principle and sound regulatory principles.

**BE IT FURTHER RESOLVED** that ENO and the Council's Advisors are directed to work together to review the FAC and recommend appropriate changes thereto.

**BE IT FURTHER RESOLVED** that the Council has exclusive regulatory jurisdiction and authority over ENO, which is a regulated public utility. The Council reserves all of its regulatory authority associated with the full array of its police and regulatory powers provided by federal, state and local law. The regulatory powers include, but are not limited to, setting rates, adjusting rates, authorizing and directing the reimbursement of monies to ratepayers, directing the terms of disposition of assets and the allocation of proceeds, enforcing the rights and interests of the City Council, the City of New Orleans and its citizens, whether for events, occurrences or matters of any type or nature, occurring prior or subsequent to the Chapter 11 filing ENO.

Nothing in this Resolution shall limit in any respect the Council's authority with regard to or participation in ENO's Chapter 11 proceeding.

**BE IT FURTHER RESOLVED** that the Council directs its bankruptcy counsel to continue to participate actively in ENO's bankruptcy proceeding to protect the rights and interests of the City Council, the City of New Orleans and its citizens.

For the foregoing reasons, the Agreement in Principle is **APPROVED**.

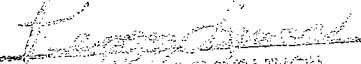
**THE FOREGOING RESOLUTION WAS READ IN FULL, THE ROLL WAS CALLED ON THE ADOPTION THEREOF AND RESULTED AS FOLLOWS:**

**YEAS:** Carter, Fielkow, Head, Hedge-Morrell, Midura, Thomas, Willard-Lewis - 7

**NAYS:** 0

**ABSENT:** 0

**AND THE RESOLUTION WAS ADOPTED..**

THE FOREGOING IS CERTIFIED  
TO BE A TRUE AND CORRECT COPY  
  
CLERK OF COUNCIL

## **AGREEMENT IN PRINCIPLE**

ENO plans to present and recommend the adoption of this Agreement in Principle to its Board of Directors. The Council's Advisors plan to present and recommend adoption of this Agreement in Principle to the Council of the City of New Orleans ("Council"). This Agreement in Principle is non-binding, and cannot be implemented without (1) ENO obtaining approval of its Board of Directors and (2) the Council adopting a Resolution approving this Agreement in Principle. The intervening parties that have filed written comments in this docket support or do not oppose this Agreement in Principle. Intervenors Sewerage & Water Board of New Orleans, New Orleans Business Energy Council, Air Products and the Alliance for Affordable Energy have worked diligently and cooperatively to develop this Agreement in Principle and to ensure that it is in the public interest.

### ***FRP Base Rates Docket UD-01-04***

1. (a) Effective with the first billing cycle of November 2006 and in accordance with Paragraph 4(a) hereinbelow, an electric base rate adjustment of 0% will be implemented.

(b) Effective with the first billing cycle of January 2008 and in accordance with Paragraph 4(b) below, an increase in electric base rates of \$3.9 million based on the current estimated revenue for the twelve months ending October 2007 of \$154.7 million will be implemented.

2. (a) Effective with the first billing cycle of November 2006 and in accordance with Paragraph 4(c) below, gas base rates will be increased by \$4.75 million as calculated based on the current estimated revenue for the twelve months ending October 2007 of \$18.1 million.

(b) Effective with the first billing cycle of November 2007 and in accordance with Paragraph 4(d) below, gas base rates will be increased by \$4.75 million as calculated based on the current estimated commodity-related revenue for the twelve months ending October 2007 of \$13.1 million.

3. Effective with the first billing cycle of March 2007 and in accordance with Paragraph 4(d) below, ENO shall effectuate through an appropriate rate schedule the continuation of the gas base rate increase provided for in Paragraph 2(a) above on a commodity revenue basis and adjust the rate for residential gas service by adjusting the monthly customer charge from \$6.20 to \$8.00 per month and shall adjust the rate for small general gas service and small municipal gas service by adjusting the monthly customer charge from \$4.08 to \$8.00 per month.

4. Rider Schedules EFRP-2 and GFRP-2 will terminate upon the date which this Agreement in Principle is made effective, except as follows:

(a) Attachment A to Rider Schedule EFRP-2 filed contemporaneously herewith shall remain in effect through the last billing cycle of December 2007.

(b) Within 10 days of Council action approving this Agreement in Principle, ENO shall file proposed rate schedules to effectuate the changes in electric base rates specified in numbered Paragraph 1(b) above, which proposed rate schedules shall be implemented (i) following Council review for the sole purpose of compliance with this Agreement in Principle and Council approval thereof, which review and approval shall occur prior to the expiration of Attachment A to Rider Schedule EFRP-2 and (ii) upon the expiration of Attachment A to Rider Schedule EFRP-2.

(c) Attachment A to Rider Schedule GFRP-2 filed contemporaneously herewith shall remain in effect through the last billing cycle of February 2007.

(d) Within 10 days of Council action approving this Agreement in Principle, ENO shall file proposed schedules to effectuate the changes in gas base rates specified in Paragraph 2(b) and 3 above, which proposed rate schedules shall be implemented (i) following Council review for the sole purpose of compliance with this Agreement in Principle and Council approval thereof, which review and approval shall occur prior to the expiration of Attachment A to Rider Schedule GFRP-2 and (ii) upon the expiration of Attachment A to Rider Schedule GFRP-2.

5. Except as provided in Paragraph 6 below, all Grand Gulf capacity costs, including that amount stated in Schedule A, shall be removed from ENO's electric base rates and shall be recovered through the fuel adjustment clause (FAC) beginning with the operations month of November 2006 and continuing through the date of implementation of new base rates set pursuant to the filing of the Base Rate Case described in Paragraph 8 hereof, unless the Council determines that full recovery of Grand Gulf capacity costs should continue through ENO's FAC following implementation of base rates resulting from the Base Rate Case described in Paragraph 8 hereof. ENO shall file contemporaneously herewith a revised Schedule FAC to reflect such modification in accordance with applicable requirements.

6. Notwithstanding the provisions of Paragraph 1(a) hereinabove, effective with the first billing cycle of November 2006 and in accordance with Paragraph 4(a) hereinabove, an electric base rate increase of 25 percent will be implemented for the LIS rate class, and thereafter, effective with the first billing cycle of January 2008, a 2.5% electric base rate increase will be implemented for the LIS rate class in accordance with Paragraph 1(b) above. This rate adjustment reflects the inclusion in the LIS rate class base rates of one-half of the Schedule A capacity costs for Grand Gulf allocable to the LIS rate class on a base rate cost responsibility basis. In addition, ENO will develop a revised FAC for the LIS rate class for the specific purpose of removing one half of ENO's Schedule A capacity costs for Grand Gulf in calculating the LIS rate class FAC costs, which shall be filed contemporaneously herewith. Thus, the LIS rate class shall pay its 100% allocable share of Grand Gulf capacity costs calculated 50% on a base rate cost responsibility basis and 50% on an energy cost responsibility basis. ENO further agrees that all incremental revenues attributed to the 25 percent base rate increase to the LIS class will be credited to ENO's monthly calculation of its fuel adjustment clause Schedule FAC-2 (as revised pursuant to paragraph 5 above), current Attachment A Page 4 of 5 Line 9 (with the line title changed to reflect the credit for the incremental revenues from the change to Rate Schedule LIS). Such credit shall be exclusive of the LIS class.

7. Except as provided for in Paragraphs 1 through 6 and 12 hereof, ENO's electric and gas base rates shall remain unchanged until implementation of electric and gas base rates resulting from the filing of a Base Rate Case as provided for in Paragraph 8 hereof.

8. On or before July 31, 2008, ENO shall file a Period I and Period II Base Rate Case using the 12 months ended December 2007 as the Period I test year and the 12 months ended December 2008 as the Period II test year. The Council's Advisors shall recommend a procedural schedule that will permit a decision by the Council on the merits of ENO's said Base Rate Case within eight months of the date of the Base Rate Case filing. In support of such action by the Council's Advisors, ENO pledges to work in a good faith manner with the Council's Advisors and any intervenors during the discovery process so as to facilitate the exchange of discovery in a timely fashion. Nothing herein shall preclude ENO from seeking approval from the Council by the filing of an application to institute appropriate Gas and Electric Formula Rate Plan mechanisms no sooner than six months following the effective date of the implementation of the base rates resulting from the said Base Rate Case.

9. ENO's Base Rate Case filing shall be based upon sound regulatory principles embodied in the conduct of a cost of service study and include, among other things:

- a. consideration of ENO's costs, service levels, and reliability pre- and post-Katrina, and the extent to which ENO's expenses reasonably can be reduced consistent with a changed customer base to achieve a balancing of ratepayer and Company interests, and consistent with sound utility practices;
- b. a class cost allocation and rate design study (to reflect post-Katrina characteristics of its customer class make-up, consumption patterns, including interruptibility of load, and cost causation) with the aim of reflecting post-Katrina conditions on the ENO system using both a Period I and Period II format; and
- c. the specific accounting treatment utilized in its Period I and Period II filings with respect to the receipt of insurance proceeds, deferred taxes, Community Development Block Grants (CDBG) and tax loss carry forwards; and,
- d. the development of appropriate customer service charges based upon accepted cost-of-service regulatory principles.

10. ENO shall submit a new depreciation study to the Council for use in its consideration and evaluation of ENO's Base Rate Case filing by May 1, 2008.

11. Commencing for the summer 2007 load period, and continuing for at least three annual periods, ENO shall seek to acquire on favorable terms and conditions and in a manner consistent with the Entergy System's standard resource planning principles and objectives adopted by the System's Operating Committee, the System Agreement, and the

current market for wholesale power, an incremental resource having the shaping characteristics described below:

Approximately 50 MW of an energy-only product at market-based heat rates or an approximate equivalent product with a lower heat rate but one that includes a capacity or reservation charge. Such product would generally be consistent with ENO's load following requirements and would include reduced or no-take provision for hourly off-peak periods.

The obligation to take output of such a product may be "shaped," such that during seasonal shoulder peaking periods, the total amount of output procured might be less than 50 MW and during the summer peaking period, the total amount procured may be more than 50 MW. ENO will pursue such a product, including longer-term products that might become available, through the Entergy System's Fall 2006 Limited Term Request for Proposals (RFP). Currently, proposals in response to that RFP are due November 16, 2006, with award notification on February 2, 2007. Thirty days following the award notification with respect to the incremental resource described herein or the decision not to accept any bids for the incremental resource described herein, the Council's Advisors shall be granted access in accordance with the applicable Confidentiality Agreement and/or Protective Order to documentation concerning the bid process and such other pertinent material as may reasonably be necessary to verify that ENO exercised prudent utility practice in the satisfaction of its obligations under this Paragraph 11.

All energy, variable O&M and fuel costs of this resource shall be recovered through the FAC, and ENO shall adhere to the provisions of Paragraph 13 below with respect to any fixed/capacity costs for which it elects to seek recovery in the FAC.

12. In addition to any rights of ENO under this Agreement in Principle or as provided by law, if an event, including, but not limited to Acts of God (e.g., weather/weather-related events, earthquake, etc.), fire, war, riots, civil unrest, public enemies (terrorist attacks), unforeseeable loss of generating capacity, changes in regulation ordered by a regulatory body, or other entity with appropriate jurisdiction, and orders or acts of civil or military authority, which event is beyond the reasonable control of the Company and is not the result of the fault or negligence or failure of due diligence by the Company, causes increased costs to ENO or results in a deficiency in revenues to ENO which is not readily capable of being addressed in a timely manner through the implementation of the base rates resulting from the Base Rate Case described in Paragraph 8 hereof, or through withdrawal of Storm Reserve funds from the Storm Reserve Fund Escrow Account pursuant to Paragraph 18 hereof, ENO may apply for expedited or emergency rate or other relief as the facts and circumstances may warrant, prior to, or during the pendency of, the said Base Rate Case. The Council shall adopt a procedural schedule for such emergency application that will permit a decision by the Council on the merits of such application within an appropriate time period taking into consideration the nature of the relief requested, ENO's financial condition and other relevant circumstances. In the event that the Council's

consideration of the merits of such application exceeds 60 days, upon an expedited hearing before the Council and a showing of good cause by ENO, the change in rates as set forth in the application shall be implemented subject to refund and become effective with the first billing cycle following expiration of the 60-day period for Council decision. In support of such expedited action by the Council, ENO pledges to work in a good faith manner with the Council's Advisors and any intervenors during the discovery process so as to facilitate the exchange of discovery in a timely fashion.

13. If ENO incurs electric capacity costs that are not currently recovered in its FAC or its electric base rates, it shall be permitted to flow these costs through the FAC, provided however, such costs:

a. are deemed to remain subject to a review under the prudent utility practice standard, including, as applicable, a demonstration that the action taken was reasonable under the then-existing circumstances (e.g., that such action would lower ENO's production costs when measured against its then-existing supply portfolio and other available market resources; or, as applicable, that such action was necessary to maintain reliability); and

b. remain in the FAC until subsequent review for a determination of appropriate prospective rate treatment by the Council.

In the FAC filing immediately following the inclusion in the FAC of capacity costs in accordance with this Paragraph, to the extent same constitutes public information, the Company will include a notice thereof describing the transaction, its costs and the reasons therefor. Contemporaneously therewith, the Company will provide any non-public information with respect to the description of the transaction, its costs and the reasons therefor to the Council's Advisors in accordance with the Protective Order applicable to Docket UD-01-4.

#### ***Storm Reserve Rider Docket UD-06-02***

14. ENO commits to work jointly with the Council in seeking an exception to the Stafford Act in Congress that will afford ENO Stafford Act protections in the event of another catastrophic event that can adversely affect its gas and/or electric systems for the ensuing ten (10) years. Such actions shall commence as soon as reasonably practical. To the extent that the Stafford Act is successfully amended to include such protections, the Storm Reserve Rider may be adjusted or eliminated to take into account such amendments, after notice and a full and fair hearing on this issue.

15. ENO shall be authorized to implement a Storm Reserve Rider, effective with the first billing cycle of March 2007, designed to accumulate a Storm Reserve principal amount of \$75 million (including accumulated interest). The Storm Reserve principal amount shall be accumulated by the collection over a ten (10) year period of a levelized amount (including a three tenths of one percent (.3%) gross-up for bad debts) allocated to ENO's gas and electric retail jurisdictions.

Within 10 days of Council action approving this Agreement in Principle, ENO shall file the Storm Reserve Rider schedule(s) consistent with the applicable terms set forth in this Agreement in Principle, which proposed rider schedule(s) shall be reviewed by the Council for the sole purpose of compliance with this Agreement in Principle; said Council review and approval shall occur prior to the last billing cycle of February 2007.

16. ENO's Storm Reserve Fund Escrow Account shall be afforded "lock box" treatment (in accordance with Paragraphs 18 and 19 below) as dedicated ratepayer funds and is to be established in a separate dedicated account to earn compound interest at market rates commensurate with the magnitude of the amount invested, which interest shall accumulate in the account and serve to reduce the principal amount required in the calculation of the annual levelized revenue requirement from ratepayers to fund the account.

17. ENO will seek to structure the Storm Reserve Fund Escrow Account in such a manner that amounts collected from ratepayers and deposited in the Storm Reserve Fund Escrow Account are not currently taxable to ENO. The monthly amount deposited in the Storm Reserve Fund Escrow Account will be the amount collected from customers via the Storm Reserve rider less all applicable taxes and account service and administration fees. Any tax treatments associated with the Storm Reserve Fund Escrow Account shall be consistent with ENO's regulatory accounting so as to not disadvantage ratepayers.

18. ENO shall ensure that ENO's Storm Reserve Fund Escrow Account shall not be used for any corporate purpose by ENO or Entergy Corporation or used as an asset of either company in a manner that is inconsistent with the use described in this Agreement in Principle. ENO shall use the Storm Reserve Fund Escrow Account only for the purpose of restoration of service in ENO's service territory attributable to a Triggering Weather Event or a series of Triggering Weather Events that occurs with respect to the ENO utility system, which Triggering Weather Event(s) shall consist of:

- a) A storm or weather event the occurrence or prospective occurrence of which prompted the issuance by the National Weather Service (or successor agency) of a "watch," "warning," or "advisory" covering at least a portion of ENO's service territory; or
- b) A "named" hurricane or tropical storm named by the National Weather Service (or successor agency); or
- c) A storm or weather event in any portion of ENO's service territory for which either 1) the President declares a "Federal Disaster Area" or makes a similar declaration and/or 2) the Governor of Louisiana declares a "State of Emergency" or makes a similar declaration; and
- d) A storm or weather/weather-related event, or a series of such events, the occurrence of which causes ENO to incur at least \$500,000 of costs in aggregate (such costs as would be accounted for as deferred O&M in Account 228 or as capital expenditures in Accounts 107 or 108 consistent with the Company's Storm Damage policy) to repair damage caused by that event and/or otherwise to restore electric and/or gas service and/or replace

or remove tangible assets in ENO's service territory in the aftermath of such an event(s); or

e) other triggering events as may be defined in the Escrow Agreement.

19. Collections from the Storm Reserve Rider shall be deposited into a restricted Escrow Account with a reputable, well-capitalized financial institution having an investment-grade credit rating of not less than "A" by Standard and Poor's or Moody's and at least \$10 billion in assets. The Escrow Agreement and any other necessary documents shall reflect the intent of this Agreement in Principle that the dedicated Storm Reserve Fund Escrow Account shall not be included in the estate of ENO for bankruptcy purposes or to satisfy creditors of ENO. The Storm Reserve Fund Escrow Account shall be considered customer-funded assets dedicated to the use described in this Agreement in Principle for all purposes including any merger of ENO, sale of ENO or surrender of ENO's franchise. The earnings (interest) on the Storm Reserve Fund Escrow Account shall be deposited into such account to be available to reimburse future storm damage costs, in accordance with Paragraphs 16 through 18 above. The actual investment returns that will be realized on the funds in the Storm Reserve Fund Escrow Account will depend, among other things, on market conditions at the time the funds are invested.

20. ENO shall make annual filings with the Council commencing on March 1, 2008 regarding the balance in the Storm Reserve Fund Escrow Account, which annual filings will report:

(a) collections, principal and interest and disbursements made in accordance with Paragraph 18 above; and

(b) the aggregate amount of costs that have been incurred by the Company for restoration of service in ENO's service territory as a result of Triggering Weather Event(s) and deferred in accordance with Paragraph 18(d) above. To the extent that the aggregate amount of costs (including amounts deferred in accordance with Paragraph 18(d)) equals or exceeds \$500,000, the Company is permitted to withdraw Storm Reserve funds from the Storm Reserve Fund Escrow Account to apply to the appropriate regulatory accounts to offset these costs in accordance with sound regulatory principles. The Company shall provide timely written notice of such withdrawal to the Council. The Council may from time to time review the disbursements from the Storm Reserve Fund Escrow Account.

o

Within 90 days of the fifth annual filing (March 1, 2012), ENO shall submit to the Council a report recommending the appropriate future level of funding of the Storm Reserve Fund Escrow Account. Upon considering ENO's filing, the Council may adjust prospectively the level of future funding upon notice and a full and fair hearing with respect to this issue.

### ***Energy Conservation and Energy Efficiency Programs***

21. ENO is committed to working actively with the Council's Advisors, the City Council, and the community to develop effective and appropriate energy efficiency and conservation programs in the New Orleans' community reflective of the community's post-Katrina needs. In furtherance of this commitment, to the extent ENO's storm-related electric uncollectible expenses have been offset as previously authorized by the Council, are deemed eligible for CDBG funds and are certified and reimbursed with CDBG funds, ENO shall make available up to \$6.9 million of such funds for energy conservation and energy efficiency post-Katrina programs in the New Orleans community as authorized by the City Council.

### ***Storm Cost Recovery Rider Relief Docket UD-06-01***

22. (a) Subject to the results of the present audit being conducted by Bruno & Tervalon, Certified Public Accountants and Paillet, Meunier and LeBlanc LLP ("Advising Auditors") in accordance with Resolution R-06-329 and assuming ENO's storm-related costs incurred through March 31, 2006 have been certified through an independent process approved by the Louisiana Recovery Authority ("LRA") for CDBG reimbursement, and CDBG funds have been received by ENO on or before March 1, 2007, ENO shall apply such CDBG funds in accordance with those amounts certified from ENO's March 31, 2006 accounting for the following items: uncollectible amounts (uncollectibles attributable to the Katrina event and on the books at the time of the event with a reversal of those already funded by prior Council actions), deferred O&M amounts, and/or capital rate base items. The procedures and deadlines for reviewing ENO's storm costs incurred through March 31, 2006 and for resolving any dispute of the findings of the Council's Advising Auditors shall be as set forth in Council Resolution R-06-329 regarding Docket UD-06-01. To the extent that it is determined that any costs included in the Company's Storm Cost Recovery Rider filing should not be characterized as storm costs, but as costs of normal on-going operations, ENO shall establish a regulatory asset to be amortized over a period of five years for inclusion and recovery of all such costs in ENO's base rates.

(b) Any CDBG funds remaining after the application of such funds to offset deferred storm costs incurred through March 31, 2006, shall be applied to offset additional certified costs as audited by the Advising Auditors. The process for reviewing ENO's storm costs incurred after March 31, 2006 and for resolving disputes regarding same shall be as set forth in the provisions of Council Resolution R-06-329 regarding Docket UD-06-01. Such process shall remain in place until such time that all costs that may be offset by the CDBG funds made available from the LRA's October 12, 2006 decision are certified.

23. In the treatment of CDBG funds used to fund capital items, for ratemaking purposes, those capital items shall be reduced by the value of the CDBG funds applied (e.g., treated for ratemaking purposes as contributions in aid of construction). The valuation of ENO's assets in Section 1 of the Settlement Ordinance of 1922 as amended

does not include any amounts funded with CDBG dollars for purposes of the City's perpetual option to purchase set forth in Section 7 of the said Settlement Ordinance.

24. As for the tax effects of the CDBG funding, ENO should apply the CDBG funds dollar for dollar against the storm costs and, to the extent the money is taxable, ENO shall create an Accumulated Deferred Income Tax account (Account 190) which will be dealt with in the subsequent Base Rate Case filing provided for in Paragraph 8 hereof (inclusive of such matters as the effect of deferred taxes and net operating loss carry forwards).

25. Until such CDBG funding is received by ENO, ENO shall account for deferred O&M accounted for in Account 228 and accumulated capital costs (Accounts 107 and 108) related to Hurricanes Katrina and Rita in accordance with the requirements stated herein. At such time CDBG funds are received, they shall offset the amounts recorded pursuant to this Paragraph. To the extent ENO incurs storm costs in excess of the CDBG funding actually received, ENO shall establish a Deferred Regulatory O&M Cost (Account 182) for any deferred O&M expenses and Account 186 for capital items.

26. Any Deferred O&M costs accounted for in Paragraph 25 in excess of CDBG funding actually received and actually incurred from 3/31/06 through 12/31/07 should be accrued and booked to the Deferred Regulatory O&M Cost Account (Account 182) and allowed to earn Louisiana's then-current legal rate of interest on the account balance, less any applicable deferred taxes. Such treatment will be recognized by the Council as a request for inclusion (under the prudence and used and useful standards as audited by the Council's Advisors) in the Deferred Regulatory O&M Account in the Base Rate Case as provided for in Paragraph 8 herein. In the event that CDBG funding is delayed beyond March 31, 2007, all dollars, without regard to the date incurred, shall accrue interest as stated in this Paragraph commencing on April 1, 2007.

27. The capital items referred to in Paragraph 25 above and recorded in ENO's Miscellaneous Deferred Debit Account in excess of CDBG funding actually received will be allowed to accumulate a carrying charge at the AFUDC rate until inclusion in the Base Rate Case filing provided for in Paragraph 8 hereof. Deferred taxes applicable to any asset in the Miscellaneous Deferred Debit Account, should be deducted prior to the calculation of the applicable AFUDC rate. In the event that the receipts of substantially all \$200 million of CDBG funding is delayed beyond March 31, 2007, all dollars, without regard to the date incurred, shall accrue the applicable AFUDC rate as stated in this Paragraph commencing on April 1, 2007.

28. If by September 1, 2007, CDBG funding of ENO's storm restoration costs has not materialized in an amount that significantly mitigates ENO's storm cost recovery request for costs incurred through March 31, 2006, ENO may file for emergency rate relief in accordance with the procedures set forth in Paragraph 12 above.

29. ENO shall cease booking any amount related to deferred O&M and capital replacements and repairs related to Hurricane Katrina and Rita beginning January 1, 2008, unless ENO discovers damages that have not been identified as of that date. In such a case,

ENO must meet the burden of proving that expenses booked after January 1, 2008 as deferred O&M expense are in fact related to Hurricane Katrina or Rita.

30. Any insurance proceeds received during the period shall be accounted for on the books of the Company so as to offset the costs of the items associated with insurance receipts (*i.e.*, items for which the insurance receipts actually reimburse the Company). To the extent such insurance proceeds are applicable to plant in service, the insurance proceeds are to be applied to the applicable depreciation reserve.

To the extent such insurance proceeds are applicable to rebuilding the natural gas plant in service, the insurance proceeds are to be accounted for in FERC Account 253 – Other Deferred Credits in accordance with the paragraph below.

Insurance proceeds shall be credited to a designated sub-account of Other Deferred Credits (Account 253) upon receipt and deposited into an interest bearing account. Interest earned on unexpended funds shall be credited to this designated sub-account of Other Deferred Credits to offset future construction expenditures. As construction costs are incurred, a concurrent entry will be made transferring an offsetting amount from the Other Deferred Credits account to CWIP as a contribution in aid of construction resulting in a permanent reduction of future depreciable plant in service. The credit balance in the Other Deferred Credits, as well as related construction expenditures remaining in the related CWIP, shall not be considered a component of rate base. AFUDC shall only be accrued in accordance with the Uniform System of Accounts Electric Plant Instruction 3(17).

31. ENO shall file with the Council by July 1, 2007 a plan of reconstruction for its damaged gas system that includes identification of relevant priorities and contingencies. Such plan should take into account among other pertinent factors, the costs and benefits of alternatives (including estimated rate impacts), sources of funding for the gas system reconstruction, and applicable repopulation and zoning plans as adopted by the appropriate governmental authority.

32. This Agreement in Principle requires that all CDBG funds received be utilized to mitigate the impact on rates on a dollar for dollar basis of ENO's eligible costs of restoration, reconstruction and rebuilding of its damaged electric and gas utility systems, and to offset such other unrecovered fixed costs as may be the responsibility of ratepayers.

### ***Miscellaneous Provisions***

33. To the extent that ENO issues notes in connection with affiliated pre-petition obligations, and such obligations are not capitalized and includable in ENO's rate base such notes (including the interest costs thereof) shall not be reflected in any manner in the calculation of ENO's retail rates, including but not limited to its capital structure, cash working capital, rate base or otherwise.

34. This Agreement in Principle reflects a compromise, settlement and accommodation among the signatories and the terms and conditions herein are interdependent. Except as otherwise expressly provided for herein, no party shall be deemed to have approved, accepted, agreed to, or consented to any ratemaking or other legal principle or policy, and nothing in this Agreement in Principle should be considered precedent for ratemaking, legal or policy purposes.

**AGREED TO BY THE FOLLOWING SIGNATORIES:**

**ADVISORS TO THE COUNCIL OF THE CITY OF NEW ORLEANS**

BY: CAV  
Clinton A. Vince

DATE: 10/26/06

**ENTERGY NEW ORLEANS, INC.**

BY: D. Packer  
Daniel F. Packer  
President & CEO

DATE: 10/26/06

SUPPORT ~~X~~

SEWERAGE & WATER BOARD OF NEW ORLEANS

BY: John H. Charanne

DATE: 10/26/2006

SUPPORT ☒

**ALLIANCE FOR AFFORDABLE ENERGY**

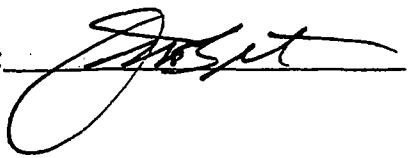
BY: Karen F. Winkelberg

DATE: 10/26/06

Q.

SUPPORT ☒

NEW ORLEANS BUSINESS ENERGY COUNCIL

BY: 

DATE: 10/26/2006

NON OPPOSITION ☒

AIR PRODUCTS AND CHEMICALS, INC.

BY: EJ Edwards

DATE: 10/27/08

## ATTACHMENT A

**ENTERGY NEW ORLEANS, INC.**  
**ELECTRIC FORMULA RATE PLAN RIDER SCHEDULE EFRP-2**  
**RATE ADJUSTMENTS**

The following Rate Adjustments will be added to the rates set out in the monthly bills of Entergy New Orleans, Inc.'s ("ENO") Rate Schedules identified below, or such additional rate schedules of ENO subject to the Electric Formula Rate Plan Rider Schedule EFRP-2 that may become effective, but not including special contracts that do not specifically provide for the application of the Rider EFRP-2. The Rate Adjustments shall be effective for bills rendered on and after the first billing cycle of November 2006.

| <b>Rate Schedules</b>                                  |                  | <b>Rate Adjustments</b> |
|--------------------------------------------------------|------------------|-------------------------|
| Residential Electric Service                           | RES-21           | 0.0000%                 |
| Master Metered Residential Apartment Service           | MMRA-1           | 0.0000%                 |
| Small Electric Service                                 | SE-21            | 0.0000%                 |
| Unmetered Service Rider                                | UMS              | 0.0000%                 |
| Master Metered Nonresidential Service                  | MMNR-17          | 0.0000%                 |
| Large Electric Service                                 | LE-21            | 0.0000%                 |
| Large Electric High Load Factor Service                | LE-HLF-5         | 0.0000%                 |
| Off Peak Service Rider 2                               | Off-Peak Rider 2 | 0.0000%                 |
| Additional Facilities Charges                          | AFC              | 0.0000%                 |
| High Voltage Service                                   | HV-21            | 0.0000%                 |
| Large Interruptible Service (Firm Portion only)        | LIS-9            | 25.0000%                |
| Experimental Interruptible Service (Firm Portion only) | EIS-14           | 0.0000%                 |
| Outdoor Directional Security Lighting Service          | ODSL-11          | 0.0000%                 |
| Outdoor Night Watchman Service                         | ONW-1            | 0.0000%                 |
| Premium Lighting Service                               | PLS              | 0.0000%                 |
| Street Lighting Service                                | SL-1             | 0.0000%                 |
| Municipal Building Lighting & Power Service            | MB-1             | 0.0000%                 |
| Traffic Signal Service                                 | TS-1             | 0.0000%                 |
| Stand-By Maintenance                                   | SMS-1            | 0.0000%                 |

**ATTACHMENT A**

**ENTERGY NEW ORLEANS, INC.  
GAS FORMULA RATE PLAN RIDER SCHEDULE GFRP-2  
RATE ADJUSTMENTS**

The following Rate Adjustments will be added to the rates set out in the Net Monthly Bill section of Entergy New Orleans, Inc.'s ("ENO") Rate Schedules identified below, or such additional rate schedules of ENO subject to the Gas Formula Rate Plan Rider Schedule GFRP-2 that may become effective, but not including special contracts that do not specifically provide for the application of the Rider GFRP-2. The Rate Adjustments shall be effective for bills rendered on and after the first billing cycle of November 2006.

| <b>Rate Schedules</b>       |       | <b>Rate Adjustments</b> |
|-----------------------------|-------|-------------------------|
| Residential Gas Service     | RGS-9 | 26.2755%                |
| Small General Gas Service   | SG-8  | 26.2755%                |
| Large General Gas Service   | LG-8  | 26.2755%                |
| Small Municipal Gas Service | SM-1  | 26.2755%                |
| Large Municipal Gas Service | LM-9  | 26.2755%                |

**ENTERGY NEW ORLEANS, INC.**  
ELECTRIC SERVICE

## RIDER SCHEDULE FAC-3

Effective: October 27, 2006  
Filed: October 27, 2006  
Supersedes: FAC-2 filed 8/25/05  
Schedule Consists of: One Sheet Plus  
Attachment A

---

**FUEL ADJUSTMENT CLAUSE**

---

**I. GENERAL****A. PURPOSE**

This Fuel Adjustment Clause ("Rider FAC") defines the procedure by which Entergy New Orleans, Inc. ("ENO" or "Company") shall recover its net fuel, purchased energy and capacity costs in accordance with the provisions of Section III of this Rider FAC. Rider FAC shall apply in accordance with the provisions of Section I.B below to electric service billed under certain rate schedules and/or rider schedules, whether metered or unmetered, subject to the jurisdiction of the Council of the City of New Orleans ("Council").

**B. FUEL ADJUSTMENT CLAUSE RATES**

The monthly rates associated with the Fuel Adjustment Clause ("Fuel Adjustment Clause Rates") shall be set forth in Attachment A, Section 4, Page 1 of 6, to this Rider FAC. The Fuel Adjustment Clause Rates shall be determined in accordance with the provisions of Sections II and III of this Rider FAC. The Fuel Adjustment Clause Rates shall be applied in accordance with the provisions set out in Attachment A to this Rider FAC. This shall constitute the maximum allowable rates. However, the Company has the obligation to minimize over-recoveries and is allowed to charge lower rates to minimize such over recoveries. To the extent that the over-recovered balance exceeds \$3 million, the Company is required to refund, in the next Rider FAC calculation, by use of a credit in the Rider FAC calculation, all of the over collection.

**II. MONTHLY FUEL ADJUSTMENT CLAUSE FILING**

On or before the first billing cycle of each month beginning in November 2006, the Company shall file a monthly Fuel Adjustment Clause Filing with the Council. The monthly Fuel Adjustment Clause Filing shall include the monthly Fuel Adjustment Clause Rates as determined by application of the formula set out in Attachment A to this Rider FAC. Each Fuel Adjustment Clause Filing shall be filed with the Council and shall be accompanied by a set of workpapers sufficient to document fully the calculations of the redetermined Fuel Adjustment Clause Rates.

**III. METHODOLOGIES****A. FUEL RATES**

The fuel rates shall be determined by using the Henry Hub Strip price for the billing month plus \$0.10/mmBtu for transportation charges and any applicable Louisiana taxes, adjusted for a 7500 Btu/kWh heat rate and converted to \$/kWh.

---

(Continued on reverse side)

## **B. CAPACITY RATES**

The capacity rates shall be determined as set forth in Attachment A, Section 1, Page 4 of 6, to this Rider FAC.

## **C. OVER / UNDER RECOVERY**

The Fuel Adjustment Clause Filing should include an over / under recovery computation to provide a true-up of Fuel Costs to actual Rider FAC revenues. This computation should be made in accordance with Attachment A, Page 2 of 6 to this Rider FAC and should include a credit for incremental revenues from any base rate increase to Rate Schedule LIS in accordance with Attachment A, Page 4 of 6 to this rider FAC.

## **D. CARRYING CHARGES ON OVER / UNDER RECOVERY**

The over / under recovery computation should include interest on the average of the balances existing at the beginning and end of the current operating month. The interest rate to be utilized is the prime bank lending rate as published in the Wall Street Journal on the last business day of each month.

## **E. CALCULATION FOR RATE SCHEDULE LIS**

The monthly FAC rate for customers taking service under Rate Schedule LIS will be calculated using actual costs for the second prior month preceding the billing month. The actual capacity costs shall be adjusted to remove 1/2 of the Schedule A Grand Gulf capacity costs included in base rates in Docket No. UD-01-04.

## **IV. CORRECTION OF ERRORS IN PRIOR PERIODS**

ENO is obligated to correct filing errors in prior period Fuel Adjustment Clause Filings. Filing errors are differentiated from vendor invoice errors or changes that occur on a continuing basis that are simply corrected in the then-current operating month's fuel costs. Filing errors in prior period filings must be described and quantified in a supplemental report in the current operating month filing. Correction of the errors will be through an addition or subtraction to the cumulative over / under recovery balance absent other direction from the Council. The correction of the error should include interest from the effective date of the error through the effective date of the correction pursuant to Section III B above.

## **V. TERM**

This Rider FAC shall remain in effect until modified or terminated in accordance with the provisions of this Rider FAC or applicable regulations or laws. Nothing herein shall prevent the Council or the Company from proposing elimination of this Rider FAC at any time in the manner provided by law.

Nothing contained in this Rider FAC shall limit the right of any party to file an appeal as provided by law.

Schedule FAC  
Attachment A  
Page 4 of 6  
Effective:  
Filed:

ENTERGY NEW ORLEANS, INC.  
**CAPACITY COST**

Data Based on Operations Month of \_\_\_\_\_  
Applied to Bill in the Month of \_\_\_\_\_

| LINE<br>NO           | DESCRIPTION                                                                                                   | REFERENCE                                  |              |
|----------------------|---------------------------------------------------------------------------------------------------------------|--------------------------------------------|--------------|
| <b>SECTION 1</b>     |                                                                                                               |                                            |              |
| <b>CAPACITY COST</b> |                                                                                                               |                                            |              |
| 1                    | Actual Capacity Cost of New Resource Plan                                                                     |                                            | \$ _____     |
| 2                    | Less Capacity Cost Incurred in Year 2001 / 12                                                                 |                                            | \$ _____     |
| 3                    | Less Reserve Equalization Incurred in Year 2001 / 12                                                          |                                            | \$ _____     |
| 4                    | Plus Reserve Equalization in Account 555                                                                      |                                            | \$ _____     |
| 5                    | Less Reserve Equalization in Account 447                                                                      |                                            | \$ _____     |
| 6                    | Plus Non-Energy Costs in FERC Accounts 501 and 547 costs (SFI Period Costs on SFI Invoice)                    |                                            | \$ _____     |
| 7                    | Plus Call Options Premium in Account 555                                                                      |                                            | \$ _____     |
| 8                    | Plus Actual Grand Gulf Non-Fuel Costs for Operations Month                                                    |                                            | \$ _____     |
| 9                    | Less Incremental Revenues from Base Rate Increase to Rate Schedule LIS                                        |                                            | \$ _____     |
| 10                   | Capacity Cost for Operations Month                                                                            | L1 - L2 - L3 + L4 - L5 + L6 + L7 + L8 - L9 | \$ _____     |
| 11                   | kWh Sales for Operations Month                                                                                |                                            | _____ kWh    |
| 12                   | Capacity Rate for All kWh Sales in Billing Month Excluding Rate Schedule EIS Available and Off-Peak kWh Sales | L10 / L11                                  | _____ \$/kWh |
| 13                   | Capacity Rate for Rate Schedule EIS Available and Off-Peak kWh Sales in Billing Month                         | L12 * 1.3                                  | _____ \$/kWh |

**ENTERGY NEW ORLEANS, INC.****LOSS FACTORS**

Data Based on Operations Month of \_\_\_\_\_

Applied to Bill in the Month of \_\_\_\_\_

| LINE<br>NO             | DESCRIPTION                                                                                          | REFERENCE         |
|------------------------|------------------------------------------------------------------------------------------------------|-------------------|
| <b>SECTION 1</b>       |                                                                                                      |                   |
| <b>SALES AND INPUT</b> |                                                                                                      |                   |
| 1                      | Non-Transmission Service Voltage Level Sales for 12 Months Ending with Operations Month              | _____ kWh         |
| 2                      | Net Area Input for 12 Months Ending with Operations Month                                            | _____ kWh         |
| 3                      | Months Ending with Operations Month Adjusted to Input Level                                          | _____ kWh         |
| 4                      | Net Area Input for Non-Transmission Service Voltage Level for 12 Months Ending with Operations Month | L2 - L3 _____ kWh |
| <b>SECTION 2</b>       |                                                                                                      |                   |
| <b>LOSS FACTORS</b>    |                                                                                                      |                   |
| 5                      | Non-Transmission Service Level Voltage Loss Factor                                                   | L4 / L1 _____     |
| 6                      | Transmission Service Level Voltage Loss Factor                                                       | 1.005262 _____    |

Schedule FAC  
Attachment A  
Page 6 of 6  
Effective:  
Filed:

**ENTERGY NEW ORLEANS, INC.**  
**CALCULATION OF RATE FOR CUSTOMERS ON RATE SCHEDULE LIS**

Data Based on Operations Month of \_\_\_\_\_  
Applied to Bill in the Month of \_\_\_\_\_

| LINE<br>NO                                          | DESCRIPTION                                                                                   | REFERENCE            |           |
|-----------------------------------------------------|-----------------------------------------------------------------------------------------------|----------------------|-----------|
| <b>SECTION 1</b>                                    |                                                                                               |                      |           |
| <b>COSTS FOR RATE SCHEDULE LIS</b>                  |                                                                                               |                      |           |
| 1                                                   | Fuel and Purchased Power Costs                                                                | Attachment A: P2 L9  | \$ _____  |
| 2                                                   | Capacity Costs                                                                                | Attachment A: P2 L10 | \$ _____  |
| 3                                                   | 1/2 of Monthly Schedule A Grand Gulf Capacity                                                 | WP8                  | \$ _____  |
| 4                                                   | Incremental Revenues from Base Rate Increase to Rate Schedule LIS Credited to Other Customers | Attachment A: P4 L9  | \$ _____  |
| 5                                                   | Total Cost for Rate Schedule LIS                                                              | L1 + L2 - L3 + L4    | \$ _____  |
| <b>SECTION 2</b>                                    |                                                                                               |                      |           |
| <b>FUEL ADJUSTMENT CLAUSE FOR RATE SCHEDULE LIS</b> |                                                                                               |                      |           |
| 6                                                   | kWh Sales for Operations Month                                                                | Attachment A: P1 L1b | _____ kWh |
| 7                                                   | Cost/kWh of Sales for the Operations Month                                                    | L5 / L6              | \$ _____  |
| 8                                                   | Transmission Service Level Voltage Loss Factor                                                | Attachment A: P5 L6  | 1.005262  |
| 9                                                   | Rate Schedule LIS FAC Rate                                                                    | L7 * L8              | \$ _____  |



# Addendum 3

Decision 20-05-053 May 28, 2020

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Case filed by Pacific Gas and Electric Company, pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.

Investigation 19-09-016

**DECISION APPROVING REORGANIZATION PLAN**

## TABLE OF CONTENTS

| Title                                                                | Page |
|----------------------------------------------------------------------|------|
| DECISION APPROVING REORGANIZATION PLAN .....                         | 1    |
| Summary .....                                                        | 2    |
| 1. Background .....                                                  | 2    |
| 1.1. Procedural Background.....                                      | 4    |
| 2. AB 1054 Scope and Schedule .....                                  | 10   |
| 3. PG&E Plan.....                                                    | 11   |
| 4. Criteria and Factors to Consider in Analyzing the PG&E Plan ..... | 13   |
| 5. PG&E Plan: Analysis, Conditions and Modifications .....           | 15   |
| 5.1. Safety, Governance Structure and Criminal Probation .....       | 15   |
| 5.1.1. Safety History.....                                           | 15   |
| 5.1.2. Executive Risk and Safety Officers .....                      | 17   |
| 5.1.3. Independent Safety Advisor .....                              | 20   |
| 5.1.4. Safety and Nuclear Oversight Committee.....                   | 23   |
| 5.1.5. Board of Directors and Holding Company .....                  | 24   |
| 5.1.6. Approval of Senior Management.....                            | 38   |
| 5.1.7. Safety and Operational Metrics.....                           | 38   |
| 5.1.8. Fines and Penalties.....                                      | 43   |
| 5.1.9. Regional Restructuring.....                                   | 45   |
| 5.1.10. Enhanced Oversight and Enforcement Process .....             | 52   |
| 5.1.11. Criminal Probation.....                                      | 64   |
| 5.2. Financial.....                                                  | 65   |
| 5.2.1. Neutral, on Average, to Ratepayers .....                      | 67   |
| 5.2.2. Securitization .....                                          | 75   |
| 5.2.3. Contributions of Ratepayers.....                              | 78   |
| 5.2.4. Financial Condition and Capital Structure.....                | 80   |
| 5.2.5. Earnings Adjustment Mechanism.....                            | 85   |
| 5.2.6. Executive Compensation.....                                   | 86   |
| 5.3. Climate.....                                                    | 94   |
| 5.4. Quality of Service and Quality of Management .....              | 95   |
| 5.5. Employees and Communities .....                                 | 96   |
| 5.6. Commission Bankruptcy Costs .....                               | 97   |
| 5.7. Other Proposals and Related Proceedings .....                   | 98   |
| 6. Comments on Proposed Decision.....                                | 101  |
| 7. Assignment of Proceeding.....                                     | 107  |
| Findings of Fact.....                                                | 107  |
| Conclusions of Law .....                                             | 109  |

ORDER .....110

**Appendix A – Enhanced Oversight and Enforcement Process**

.

## **DECISION APPROVING REORGANIZATION PLAN**

### **Summary**

This decision approves, with conditions and modifications, the reorganization plan of Pacific Gas and Electric Company (PG&E) and its holding company PG&E Corporation (PG&E Corp.) pursuant to the requirements of Assembly Bill 1054 (Ch. 79, Stats. 2019). Changes to PG&E's governance structure and enhancements to the Commission's oversight are put in place to facilitate PG&E's ability to provide safe, reliable and affordable utility service.

The Commission expects that there will need to be further adjustments and refinements to the course charted by this decision, but with today's decision the Commission has crafted additional tools to effectively respond to new developments and make any necessary changes. The Commission has already identified a number of areas that need further analysis and development in order to be fully implemented, and those will be addressed in this or other Commission proceedings. This proceeding remains open.

### **1. Background**

Pacific Gas and Electric Company (PG&E) and its holding company PG&E Corporation (PG&E Corp.) (jointly Debtors) filed voluntary bankruptcy petitions on January 29, 2019, under Chapter 11 of the U.S. Bankruptcy Code. The Debtors' filings came after a series of major wildfires, including fires for which PG&E expected to be held liable. At the outset, the Commission acknowledges the devastation caused by these fires and the tragic losses suffered by Californians in these catastrophes. A key requirement of PG&E is to provide compensation to wildfire victims as part of any plan for reorganization in the Chapter 11 case to allow the Debtors to exit bankruptcy. (Public Utilities Code Section 3292(b)(1)(B).)

California Assembly Bill (AB) 1054 (Ch. 79, Stats. 2019) subsequently established a Wildfire Fund to pay eligible claims to victims of wildfires caused by utility infrastructure. (Public Utilities Code section 3288(b).) The fund is expected to be capitalized with approximately \$21 billion in revenue contributed approximately equally from utility ratepayers and utility shareholders. (See Decision (D.) 19-10-056 at 34 (Rulemaking (R.) 19-07-017; October 24, 2019.)) California electrical corporations, such as PG&E, can participate in the fund if they meet certain criteria. One of the criteria that PG&E must satisfy to participate in the fund is that its “insolvency proceeding” (*i.e.* bankruptcy) must be “resolved pursuant to a plan or similar document not subject to a stay” by no later than June 30, 2020. (Public Utilities Code Section 3292(b).)

In addition, AB 1054 requires the Commission to complete certain tasks by June 30, 2020, including:

- (C) The commission has approved the reorganization plan and other documents resolving the insolvency proceeding, including the electrical corporation’s resulting governance structure as being acceptable in light of the electrical corporation’s safety history, criminal probation, recent financial condition, and other factors deemed relevant by the commission.
- (D) The commission has determined that the reorganization plan and other documents resolving the insolvency proceeding are (i) consistent with the state’s climate goals as required pursuant to the California Renewables Portfolio Standard Program and related procurement requirements of the state and (ii) neutral, on average, to the ratepayers of the electrical corporation.
- (E) The commission has determined that the reorganization plan and other documents resolving the insolvency proceeding recognize the contributions of ratepayers, if any, and compensate them accordingly through

mechanisms approved by the commission, which may include sharing of value appreciation. (Public Utilities Code Section 3292(b)(1).)

In order for PG&E to meet the deadline for resolution of its bankruptcy proceeding, the Commission must make these determinations before June 30, 2020. This is a short deadline and has required the Commission to follow an aggressive schedule in this proceeding.

### **1.1. Procedural Background**

The Commission Order Instituting Investigation (OII) for this proceeding was issued on October 4, 2019. PG&E and numerous other parties filed responses to the OII. A pre-hearing conference (PHC) was held on October 23, 2019. An Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) was issued on November 14, 2019, setting forth the schedule for the proceeding and the issues to be addressed.

At the time the PHC was held and the Scoping Memo was issued, there were two competing plans of reorganization before the Bankruptcy Court and thus pending before the Commission: one from PG&E (PG&E Plan) and one from the Ad Hoc Committee of Senior Unsecured Noteholders of Pacific Gas and Electric Company (AHC) supported by the Official Committee of Tort Claimants of Pacific Gas and Electric Company (TCC) (TCC/AHC Plan). When the Scoping Memo was issued there was also uncertainty relating to the total amount of allowed claims PG&E must satisfy through reorganization, and it was anticipated that it could take some time to determine the amount of those claims. In order to move the proceeding forward while waiting for that information, the schedule established at that time had the Commission consider non-financial issues first, and consider financial issues later, when it was anticipated that there would be greater certainty. (Scoping Memo at 3, 9-10.)

In response to disagreement among the parties about the applicability of Public Utilities Code Section 854 to the plans of reorganization, the Scoping Memo allowed for briefing on the applicability of Section 854. Parties filed briefs on that issue on November 21, 2019, and a ruling was issued on November 27, 2019 resolving the issue as follows:

The following criteria from Public Utilities Code Section 854 are made applicable to the plans of reorganization pursuant to Section 853(b)(c):

- (1) Maintain or improve the financial condition of the resulting public utility doing business in the state.
- (2) Maintain or improve the quality of service to public utility ratepayers in the state.
- (3) Maintain or improve the quality of management of the resulting public utility doing business in the state.
- (4) Be fair and reasonable to affected public utility employees, including both union and nonunion employees.
- (6) [sic] Be beneficial on an overall basis to state and local economies, and to the communities in the area served by the resulting public utility.<sup>1</sup>

The ruling noted that while the Commission will consider each of these criteria in evaluating a reorganization plan, it is not mandatory that a reorganization plan satisfy each of these criteria.

On December 13, 2019, opening testimony on non-financial issues was served by PG&E, AHC, The Utility Reform Network (TURN), William B. Abrams (Abrams), the California Large Energy Consumers Association (CLECA), and Small Business Utility Advocates (SBUA), consistent with the schedule established in the Scoping Memo. Also, on December 13, 2019, PG&E filed a Notice of Amended Plan of Reorganization. The changes to PG&E's Plan

---

<sup>1</sup> *Administrative Law Judge's Ruling on Public Utilities Code Section 854* at 11-12.

resulted in TCC switching its support from the AHC Plan to the PG&E Plan, and clarification of the amount of claims that PG&E must satisfy through reorganization.

A Status Conference was held on December 20, 2019 to address these new developments, and how they impacted the schedule for the proceeding. A ruling issued on December 27, 2019 held that:

Now, however, due to subsequent developments, including the Amended Plan of Reorganization from PG&E, it is no longer necessary to wait for the outcome of the estimation and Tubbs proceedings in order to address the financial issues. At a Status Conference held on December 20, 2019, there was consensus that it now makes more sense to re-combine the two separate phases into one phase addressing both financial and non-financial issues. (Administrative Law Judge's Ruling Modifying Schedule at 3.)

That ruling accordingly established a new schedule for the proceeding. On January 16, 2020, PG&E filed a motion requesting an extension of time to serve its testimony, on the grounds that:

The requested schedule modification would permit the parties and the Commission to consider testimony describing further developments that may result from ongoing discussions with the Ad Hoc Committee of Bondholders (AHC) regarding a potential settlement. The AHC supports the relief sought in this motion. In addition, an extension would permit the presentation of consolidated opening testimony describing any further amendments to PG&E's Plan of Reorganization that may result from ongoing discussions with the California Governor's Office (the "Governor's Office"). (PG&E's Motion to Modify Schedule at 1.)

A ruling issued later on January 16, 2020 granted PG&E's motion in part and modified the schedule, moving the date for PG&E's testimony from

January 22 to January 31, 2020, and moving reply testimony from February 7 to February 14, 2020.<sup>2</sup>

On January 23, 2020, AHC filed a motion to withdraw from the proceeding, stating:

On January 22, 2020, the Ad Hoc Committee executed a Restructuring Support Agreement (RSA) with Pacific Gas and Electric Company (PG&E) and PG&E Corporation (collectively, the “Debtors”). The RSA requires the Ad Hoc Committee, in relevant part, to file motion(s) for leave to withdraw all filings submitted in any proceeding before the Commission involving the Debtors and cease participation in any proceeding before the Commission involving the Debtors, as set forth in the RSA. (Motion of AHC to Withdraw at 1.)

A ruling issued on January 30, 2020 granted AHC’s request to withdraw from the proceeding but denied its request to withdraw previously-filed pleadings in the proceeding.<sup>3</sup> As a result, only one plan – the PG&E Plan – remained before the Commission.

On January 31, 2020, PG&E served its opening testimony, consisting of one volume of testimony and five volumes of supporting exhibits. PG&E’s testimony was organized by chapters: Introduction; PG&E’s Plan and Financing; Ability to Raise Capital Post-Emergence; Board-Level Governance; Utility Safety and Governance; Wildfire Safety; Executive Compensation; Governance: Probation; Climate; Rates and Rate Neutrality; Fines and Penalties; and Section 854 Considerations.

Reply testimony was due to be served on February 14, 2020, but on February 10, 2020, TURN, with other parties either supporting or not opposing,

---

<sup>2</sup> I.19-09-016 PG&E Bankruptcy - E-Mail Ruling Granting in Part Motion to Modify Schedule (PG&E)

<sup>3</sup> Administrative Law Judge’s Ruling Granting in Part Motion to Withdraw from Proceeding at 4-5.

requested an extension of time to serve testimony and a delay in the start of evidentiary hearings. That request was granted, moving reply testimony to February 21, 2020, and evidentiary hearings to February 25, 2020.<sup>4</sup>

On February 18, 2020, an Assigned Commissioner's Ruling (ACR) set forth a set of proposals to ensure development of the record in the proceeding on issues relating to governance, management, and oversight of the Debtors.

On February 21, 2020, reply testimony was served by Natural Resources Defense Council (NRDC), Coalition of California Utility Employees (CUE), City and County of San Francisco (CCSF), TURN, Alliance for Nuclear Responsibility (A4NR), Abrams, CLECA, and SBUA. TURN also served joint testimony with the Energy Producers and Users Coalition (EPUC) and the Indicated Shippers (IS). Five northern California community choice aggregators served joint testimony: East Bay Community Energy, Peninsula Clean Energy Authority, Monterey Bay Community Power, City of San Jose (on behalf of San Jose Clean Energy) and Silicon Valley Clean Energy Authority (Joint CCAs). PG&E also served supplemental testimony including errata on February 21, 2020.

Evidentiary hearings were held in San Francisco beginning on February 25, 2020 and running through March 4, 2020. PG&E and the other parties that served testimony were subject to cross-examination on their testimony. The procedural schedule was further modified to allow parties time to submit comments on the proposals set forth in the February 18, 2020 Assigned Commissioner's Ruling.<sup>5</sup>

---

<sup>4</sup> *Administrative Law Judge's Ruling Modifying Schedule*, dated February 11, 2020.

<sup>5</sup> *See, Administrative Law Judge's Ruling Confirming Modification of Procedural Schedule*, dated March 6, 2020.

On March 13, 2020, parties filed opening comments on the proposals in the ACR and opening briefs on the other issues.<sup>6</sup> Briefs were filed by A4NR, CUE, Marin Clean Energy (MCE), Joint CCAs, EPUC/IS, South San Joaquin Irrigation District (SSJID), Next Era Energy Resources LLC (Next Era), TURN, Center for Energy Efficiency and Renewable Technologies (CEERT), CLECA, CCSF, PG&E, TCC, City of San Jose (San Jose), Abrams, SBUA<sup>7</sup> and the Commission's Public Advocates Office (Cal Advocates).

Parties were provided an opportunity to request evidentiary hearings on the proposals in the ACR, but no party requested hearings.

On March 24, 2020, PG&E filed a motion for official notice of documents filed in the Bankruptcy Court on March 20, 2020, including the "Debtors' Motion Pursuant [...] for Entry of an Order (I) Approving Case Resolution Contingency Process, and (II) Granting Related Relief," and "Governor Gavin Newsom's Statement in Support of Debtors' Motion Pursuant [...] for Entry of an Order (I) Approving Case Resolution Contingency Process, and (II) Granting Related Relief." PG&E's motion for official notice was granted on March 24, 2020, providing parties in this proceeding an opportunity to address those documents in their subsequent pleadings. On April 9, 2020, the bankruptcy court entered an Order approving the case resolution contingency process. (*Debtors' Joint Chapter 11 Plan of Reorganization*, Case: 19-30088, Doc# 6721.)

---

<sup>6</sup> While each pleading contained both comments and a brief, for the sake of brevity and consistency they will be referred to in this decision as briefs.

<sup>7</sup> SBUA was granted leave to file its brief on March 16, 2020.

On March 26, 2020, reply briefs and reply comments<sup>8</sup> were filed by A4NR, CLECA, Joint CCAs, CUE, EPUC/IS, Cal Advocates, CCSF, CEERT, TCC, PG&E, TURN, Abrams,<sup>9</sup> and SBUA.

## **2. AB 1054 Scope and Schedule**

AB 1054 requires the Commission to examine complex and important questions relating to PG&E's plan of reorganization, including PG&E's governance structure. This is not a simple analysis, and getting it right is essential to PG&E, its customers, and California. At the same time, however, AB 1054 sets a very short deadline: for PG&E to participate in the wildfire fund, the Bankruptcy Court and the Commission must approve the reorganization plan and other documents resolving the insolvency proceeding by June 30, 2020. As a practical matter, however, if the Commission is going to approve those documents it must do so before that date in order to coordinate with the Bankruptcy Court proceedings. As described above, this requires an accelerated procedural schedule; nevertheless, the parties submitted substantial testimony and briefing on PG&E's plan and the ACR proposals, but the schedule does not allow for an in-depth discussion in this decision on every detail of PG&E's plan or the various proposals to modify or add to that plan.

The result is a tension – how can the Commission best balance these competing needs of ensuring that the plan satisfies the requirements of AB 1054 while also meeting the deadline set in AB 1054. One party, Abrams, argued that the Commission should not feel bound by the deadline set in AB 1054, and should take as much time as it deems necessary, on the grounds that the deadline

---

<sup>8</sup> While each pleading contained both reply comments and a reply brief, for the sake of brevity and consistency they will be referred to in this decision as reply briefs.

<sup>9</sup> Abrams filed his reply brief on March 20, 2020.

is a deadline for PG&E, not the Commission. (Transcript v. 6 at 1088.) Other parties expressed concern about the pace of the proceeding, but no other party took this position. Some other parties did recommend the Commission reject the plan, which would have a similar result. (*See*, CCSF Brief at 3-4, Joint CCA Brief at 2, 15, 19.) Those parties did, however, plead that rejection in the alternative along with proposed modifications or conditions that would enable the Commission to approve the plan.

It is clear that the intent of the legislature was to strongly incentivize resolution of PG&E's bankruptcy and related Commission approvals by June 30, 2020.<sup>10</sup> Victims of the wildfires cannot receive compensation for their losses until PG&E exits bankruptcy, and it is a statutory requirement for PG&E to access the wildfire fund going forward. Accordingly, the Commission has worked arduously with the assistance of parties to resolve the issues before us in this proceeding as completely as possible in the limited time available. While some issues may be able to be completely resolved in this decision, others will need further analysis and consideration to ensure a good resolution. On those issues the Commission will take the initial steps here to begin the necessary work and provide direction and guidance, but more work will remain to be done after this decision.

### **3. PG&E Plan**

PG&E's plan has both financial and non-financial aspects. On the financial side, the plan calls for PG&E to refinance higher-cost prepetition debt with lower cost debt, resulting in potentially significant interest rate savings. In its

---

<sup>10</sup> The recent "Case Resolution Contingency Process" presented in the Bankruptcy Court, which provides for the commencement of a sale process if a confirmation order is not entered by June 30, 2020, appears to confirm that the Governor's Office has the same intent.

testimony, PG&E summarizes the funding of its plan and the associated uses of that funding as follows:

TABLE 2.1: SOURCES &amp; USES

| SOURCES                                   |                         | USES                                  |                                    |
|-------------------------------------------|-------------------------|---------------------------------------|------------------------------------|
| <b>New Equity in PG&amp;E Corporation</b> | \$15.75 billion         | <b>Fire Claims</b>                    | <b>\$24.15 billion<sup>1</sup></b> |
| New money equity raise                    | \$9 billion             | <b>Contribution to Wildfire Fund</b>  | <b>\$5 billion</b>                 |
| Equity issued to Fire Victim Trust        | \$6.75 billion          | <b>Debtor-In-Possession Financing</b> | <b>\$2 billion</b>                 |
| <b>New PG&amp;E Corporation Debt</b>      | <b>\$4.75 billion</b>   | <b>Prepetition Debt</b>               | <b>\$22.18 billion</b>             |
| <b>Reinstated Utility Debt</b>            | <b>\$9.575 billion</b>  | <b>Trade Claims and Other Costs</b>   | <b>\$2.3 billion</b>               |
| <b>New Utility Debt</b>                   | <b>\$23.775 billion</b> | <b>Accrued Interest</b>               | <b>\$1.27 billion</b>              |
| Refinancing of Pollution Control Bonds    | \$0.1 billion           | <b>Cash</b>                           | <b>\$0.75 billion</b>              |
| Noteholder RSA debt                       | \$11.85 billion         | <b>Total Uses</b>                     | <b>\$57.65 billion</b>             |
| New debt                                  | \$5.825 billion         |                                       |                                    |
| Temporary Utility Debt                    | \$6 billion             |                                       |                                    |
| <b>Insurance Proceeds</b>                 | <b>\$2.2 billion</b>    |                                       |                                    |
| <b>Cash at Emergence</b>                  | <b>\$1.6 billion</b>    |                                       |                                    |
| <b>Total Sources</b>                      | <b>\$57.65 billion</b>  |                                       |                                    |

(Table 2-1 from page 2-2 of Ex. PG&E-1.)

PG&E also provides an overview of its plan in its Brief. (PG&E Brief at 15-27.) According to PG&E, its plan addresses the following elements:

- 1) Wildfire Claims. PG&E's plan provides for payment of \$25.5 billion<sup>11</sup> in settlement of Fire Claims, defined as any past, present, or future claims related to specified wildfires that occurred in Northern California in 2015 through 2018, and includes four different classes of Fire Claims: Fire Victim Claims; Public Entities Wildfire Claims; Subrogation Wildfire Claims; and Subrogation Butte Fire Claims. (PG&E Brief at 15-18.)
- 2) Other Claims. PG&E's plan resolves other prepetition claims against PG&E in the following areas: Funded Debt Claims; Employee-Related Claims; General Unsecured Claims; Ghost

<sup>11</sup> The \$24.15 billion shown in the table does not include \$1.35 billion in deferred payment to the Fire Victims Trust. (Ex. PG&E-1 at 2-2.)

Ship Fire Claims; Priority Tax And Priority Non-Tax Claims; Subordinated Debt Claims; Common Interests; Administrative Expense Claims; and Environmental Claims. (PG&E Brief at 19-23.)

- 3) Participation in the Wildfire Fund. PG&E believes that its plan will enable it to participate in AB 1054's statewide Wildfire Fund upon its emergence from bankruptcy. (PG&E Brief at 23-24.)
- 4) Assumption of Agreements. PG&E's plan provides for the assumption of all power purchase agreements, renewable energy power purchase agreements and Community Choice Aggregation servicing agreements, as well as all Employee Benefit Plans and Collective Bargaining Agreements. (PG&E Brief at 24-25.)

There are many other details to PG&E's plan of reorganization; the Commission's review here focuses on those elements of the plan required for the Commission's approval under AB 1054.

#### **4. Criteria and Factors to Consider in Analyzing the PG&E Plan**

In analyzing the PG&E Plan under AB 1054 the Commission must determine whether the plan, including the resulting governance structure, is acceptable. The criteria that AB 1054 requires the Commission to consider in making that determination are PG&E's safety history, criminal probation and recent financial condition. Under AB 1054 the Commission may also consider other factors that the Commission deems to be relevant. In addition, AB 1054 requires the Commission to determine if the plan is consistent with the state's climate goals, is neutral, on average, to PG&E ratepayers, and recognizes the contribution of ratepayers. (Public Utilities Code Section 3292(b)(1).) These express approvals required under AB 1054 are in addition to the Commission's general ratemaking authority: as the Bankruptcy Code explicitly recognizes, any rate change proposed in a reorganization plan must be approved by the

governmental regulatory commission with proper jurisdiction. (Decision (D.) 03-12-035 at 23, quoting *In re Cajun Elec. Power Co-op., Inc.* (5th Cir. 1999) 185 F.3d 446, 453).

As this case has evolved, the Commission has identified additional factors and criteria it will consider in this proceeding. Those factors and criteria are set forth in the Order Instituting Investigation (OII) that initiated this proceeding, in the Assigned Commissioner's Scoping Memo and Ruling, in the Administrative Law Judge's Ruling on Public Utilities Code section 854 and the February 18, 2020 Assigned Commissioner's Ruling and Proposals (ACR).

Those factors are: how the plan and proposed governance structure will affect public safety on a going forward basis, both short term and long term; the ratemaking implications of the plan; whether the plan provides satisfactory resolution of claims for monetary fines or penalties for PG&E's pre-petition conduct; whether the plan maintains or improves PG&E's financial condition; whether the plan maintains or improves the quality of service to PG&E rate payers; whether the plan maintains or improves the quality of management of PG&E; potential effects of the plan on local communities and PG&E employees; whether the plan is fair and reasonable to PG&E employees; and whether the plan is beneficial on an overall basis to state and local economies and to the communities in the area served by PG&E.

In addition, the parties and the February 18, 2020 ACR presented multiple proposals that would supplement PG&E's plan. Some of those fall within one or more of the above factors and criteria, while others are stand-alone proposals.

## **5. PG&E Plan: Analysis, Conditions and Modifications**

Examination of PG&E's reorganization plan generally can be broken down into categories of safety-related issues, financial issues, and other issues. This decision examines the plan in that order.

### **5.1. Safety, Governance Structure and Criminal Probation**

In this section we consider non-financial issues relating to the reorganization plan and the resulting governance structure, including safety history, safety-related changes to PG&E's governance structure, including ACR proposals on Executive Level Risk and Safety Officers, Independent Safety Advisor, Expanded Safety and Nuclear Oversight Committee Authority, Board of Directors, Approval of Senior Management, Safety and Operational Metrics, and Regional Restructuring. Also considered in this section are PG&E's safety-related Fines and Penalties and Criminal Probation.

We will address safety-related issues and governance structure issues together, as the changes in governance structure are intended to improve PG&E's safety performance, including regional restructuring. PG&E's criminal probation is discussed here, as it stems from a safety failing that resulted in a criminal conviction.

#### **5.1.1. Safety History**

In order for the Commission to approve PG&E's reorganization plan under AB 1054, the Commission must find that the reorganization plan (and other documents resolving the insolvency proceeding) is "acceptable in light of the electrical corporation's safety history." Somewhat oddly, PG&E's testimony in this proceeding simply does not address its safety history. PG&E's January 31, 2020 testimony includes two chapters that address safety: Chapter 5

“Utility Safety and Governance,” and Chapter 6, “Wildfire Safety.” Those chapters address the activities that PG&E has undertaken or is undertaking to improve its safety record, but do not address its safety history.

It is understandable that PG&E may want to shift the focus away from the history of its recent safety performance - which has ranged from dismal to abysmal - and instead seek to draw attention to its remedial efforts. At the same time, however, this is a cause for concern, as PG&E seems reluctant to take ownership of its own safety history and acknowledge its failings. PG&E’s safety history is, however, well documented elsewhere, including Commission decisions and other parties’ testimony and pleadings.

Much of the discussion of PG&E’s safety history in this proceeding started with the 2010 San Bruno gas pipeline explosion that killed 8 people, injured 58 people, and destroyed 38 homes. (*See, e.g.* Cal Advocates Brief at 17-18.) It is important to keep in mind that PG&E’s safety problems did not start then, however. There were incidents prior to 2010, such as the 2008 Rancho Cordova gas explosion that killed one person, injured five others and destroyed a house. Since 2010, there have been a series of events, both large and small, that show that PG&E has a serious safety problem that has remained unresolved, despite the imposition of massive fines by this Commission and other penalties, including a criminal conviction. PG&E’s botched demolition of its Kern Power Plant resulted in the death of a worker in 2012 and injuries to five spectators in 2013. In 2014, a PG&E gas explosion destroyed a house in Carmel, PG&E’s Metcalf Substation was burglarized, and a City of San Jose employee was injured due to PG&E’s failure to properly mark the location of its (improperly installed) underground electrical line.

Then came the fires: the 2015 Butte Fire (two deaths), the 2017 Redwood Fire (nine deaths), Atlas Fire (six deaths), and the 2018 Camp Fire (86 deaths), with tens of thousands of homes and structures destroyed and hundreds of thousands of acres burned. (*See*, Cal Advocates Brief at 17-18.)

On the witness stand, PG&E Corp. CEO Johnson was asked about PG&E's safety history:

Q: So it's not a good safety history, is it?

A: No. It is what it is. How about that? A lot of issues, big issues. But you can characterize it however you would like. But it's plenty of the challenges in that history. (Transcript v. 1 at 55.)

When pushed, Johnson acknowledged that there were "[S]ubstantial problems in the past of safety leading to catastrophe to fatality." (*Id.* at 57.) But he also repeatedly sought to shift the focus back onto what he and PG&E were doing now.

This Commission has previously noted that PG&E's top management has been resistant to acknowledging its responsibility for PG&E's failings (*see, e.g.* D.20-02-036 at 24-25), but the bottom line for this proceeding, however, is whether the plan of reorganization (and related documents) are acceptable in light of PG&E's safety history. Given that safety history, the key question is whether PG&E's plan and any conditions imposed by the Commission in connection with our decision approving the plan, will improve PG&E's safety performance. Accordingly, it is appropriate to look at the proposals before us, including those proposed by PG&E as well as those adopted from the ACR, for PG&E to improve its safety performance going forward.

#### **5.1.2. Executive Risk and Safety Officers**

ACR Proposal 1 adds refinements and details to PG&E's proposal to establish an executive-level Chief Risk Officer (CRO) and Chief Safety Officer

(CSO). The ACR calls for specific lines of reporting, for the CRO to appear before the Commission or meet with Commission staff at least quarterly, plus the CSO would provide semi-annual performance reports to Commission staff. Additional requirements for appointment to the two positions were also recommended.

PG&E expressed general support for ACR Proposal 1, and agreed that the CSO should have a public safety focus as well as a workforce safety focus, and that the CRO and CSO positions remain in place until the Commission determines they are no longer necessary. PG&E recommended that regional safety reporting should be to the CSO, not the CRO, as PG&E believes that risk should be evaluated on an enterprise and line of business perspective, while safety efforts to address those risks are more appropriate for a regional approach. (PG&E Brief at 126-129.)

Other parties were generally supportive of ACR Proposal 1, but recommended some modifications. TURN argues that from PG&E's description, the duties of the CRO and CSO overlap, and that may result in lack of accountability and misunderstandings. TURN accordingly recommends that PG&E just have a CRO, or to have the CSO report to the CRO, rather than having two equal level senior managers. (TURN Brief at 58.)

Cal Advocates recommends that the CEO of PG&E be designated as PG&E's "Accountable Officer" to establish safety accountability using the same language as Canadian National Energy Board. (Cal Advocates Reply Brief at 7.) Cal Advocates also notes that PG&E's definition of the CSO role is focused on workplace safety, rather than public safety, but instead of expanding the duties of the position, Cal Advocates recommends that PG&E have separate officers dedicated to workplace and public safety. (Cal Advocates Brief at 12.)

CCSF similarly recommended that the roles and responsibilities of the two positions be more clearly defined, and to have the CSO oversee public safety as well as workplace safety. (CCSF Brief at 22-24.)

TCC likewise believes that the CSO position needs to prioritize public safety, and TCC supports the proposal's requirement that the CRO and CSO have reporting from safety officers and employees and contractors in the field in order to identify public safety concerns in a timely manner and the ability to report those concerns up to the Safety and Nuclear Oversight (SNO) Committees and the CEOs of both PG&E and PG&E Corporation. (TCC Brief at 19-20.)

After considering the recommendations of the parties, the Commission adopts the recommendations of ACR Proposal 1 that PG&E have a separate CRO and CSO, the CSO's duties include both public and workplace safety, and that both the CRO and CSO get direct reporting from safety officers in the field, with regional issues reported to the CSO and line of business issues reported to the CRO. Both the CRO and CSO should have regular contact with PG&E employees and contractors working in the field, and both the CRO and CSO should be empowered to report directly to the SNO Committees and CEOs of PG&E and PG&E Corp. PG&E should consult with the State regarding the appointment of the initial CRO and CSO; subsequent appointments must be approved by PG&E's SNO Committee. The CRO and CSO will be required to provide regular periodic reports to the Commission and/or Commission staff.

Further clarification and refinement of the roles of the CRO and CSO and their reporting requirements, both to the Commission and within PG&E, is necessary, and will be addressed in the PG&E Safety Culture Investigation (I.15-08-019) or other appropriate proceeding.

### **5.1.3. Independent Safety Advisor**

ACR Proposal 2 calls for PG&E to appoint an Independent Safety Advisor that would functionally act in the same capacity as the federal court monitor after the termination of the federal monitor, and would work with the CRO, CSO and PG&E's management team and board to develop recommendations to address compliance issues and enhance PG&E's safety performance.

PG&E supports the appointment of an Independent Safety Advisor after the termination of the federal court monitor, but opposes a determination at this time that the Independent Safety Advisor would functionally serve in the same capacity as the federal court monitor. PG&E instead recommends that PG&E would file an advice letter four months prior to the end of the federal monitor's term proposing the function of the Independent Safety Advisor based on PG&E's experience with the current Federal Monitor and PG&E's newly created Independent Safety Oversight Committee. (PG&E Brief at 134-135.) PG&E also recommends a process for the Commission to establish a budget for the work of the Independent Safety Advisor, and that PG&E could request recovery in rates of the costs and expenses of the Independent Safety Advisor within the approved budget. (*Id.* at 135.) PG&E also recommends that the Independent Safety Advisor position would sunset after 2025, unless the Commission extends that date. (*Id.*)

CCSF believes that given PG&E's safety history the Commission should require a monitor rather than an advisor, and that PG&E's plans for an advisor "[F]all short of what the Commission should require." (CCSF Brief at 26.)

CCSF recommends that:

In light of PG&E's record, the Commission should require oversight from an independent safety monitor with authority to warn the Commission of its safety concerns, instruct PG&E

to take certain actions, and recommend that the Commission step in if PG&E fails to take those actions. In order for the monitor to be effective, the Commission should be responsible for hiring and supervising the independent safety monitor, who should also report directly to the Commission. (CCSF Brief at 26.)

CCSF also opposes PG&E's recommendation that the independent safety monitor's role should end in 2025, but instead recommends that the Commission establish specific, verifiable safety standards that PG&E must meet before determining that an independent safety monitor is no longer needed. (*Id.* at 26.)

CCSF calls for the independent safety monitor, like the federal court monitor, to be able to access support from attorneys and experts as necessary, and for PG&E to provide full access to its employees, facilities and records. (*Id.* at 26-27.)

TURN, while generally supporting ACR Proposal 2, agrees with CCSF that there should be a monitor reporting to the Commission, rather than an advisor reporting to PG&E: "First, TURN strongly believes that the successor to the current Federal Monitor should continue to be a truly independent Monitor who is appointed by and reports to the CPUC." (TURN Brief at 60.)

TURN also calls for more transparency regarding the monitor's work and findings, so that the public has some idea of what work the monitor is actually doing, and can have some confidence in that work.

Again, similar to CCSF, TURN argues that the new independent safety monitor should have unbridled access to PG&E documents and personnel, and "[S]hould generally be patterned on the Federal Monitor in terms of scope of authority, staff support, and Utility payment of fees and costs." (*Id.* at 61.)

TURN does not oppose PG&E's proposal to have PG&E file an advice letter to propose the detailed functions of a monitor. (TURN Reply Brief at 48.)

TURN opposes an automatic or default sunset of the independent safety monitor in 2025, and instead recommends that PG&E should have to demonstrate that the position is no longer needed, which PG&E could do via a Tier 3 Advice Letter that shows that PG&E has been successful at operating safely since its exit from bankruptcy and that the monitor is no longer needed. (*Id.*)

PG&E only obliquely addresses the recommendations of CCSF and TURN, but mostly just reiterates its proposal to defer defining the role of the advisor until closer to the end of the federal court monitor, at which time PG&E would file an advice letter “[P]roposing the function of the Independent Safety Advisor.” (PG&E Reply Brief at 82-83.)

While the Commission finds some merit to the recommendations of CCSF and TURN, we are also persuaded by PG&E that the Commission should consider PG&E’s additional experience with both the Independent Safety Oversight Committee and the Federal Monitor at the point in time when the Commission determines the function, scope of work, and reporting requirements for this role. Accordingly, this decision directs that there will be an Independent Safety Monitor that will report to the Commission and be functionally equivalent to the federal court monitor. Other details for implementing the Independent Safety Monitor are reserved for future consideration, such as the Monitor’s selection and appointment, its exact scope of duties, reporting requirements and budget and cost recovery. PG&E is directed to submit a Tier 3 Advice Letter to the Commission no later than one year before the expiration of the term of the federal court monitor, with a proposed scope of work, budget, solicitation process, and a process for selection/approval by the Commission. Energy Division will process the Tier 3 Advice Letter in consultation with the

Commission's Safety Enforcement Division and Safety Policy Division, as appropriate.

#### **5.1.4. Safety and Nuclear Oversight Committee**

ACR Proposal 3 clarifies and expands the authority of the Safety and Nuclear Oversight (SNO) Committees of PG&E's boards of directors. Specifically, the SNO Committees would have oversight over PG&E's Wildfire Mitigation Plan, Public Safety Power Shutoff (PSPS) program, compliance with the Safety and Operational Metrics in ACR Proposal 7, periodic reporting to the boards of directors and Commission staff, and PG&E's response to the recommendations of the Independent Safety Advisor recommended in ACR Proposal 2. In addition, the SNO Committees would have the authority to hire third-party safety and utility operations experts. Selection of the initial members of the SNO Committees would incorporate consultation with, or approval of, the State and Commission staff.

PG&E supports this proposal for expanded oversight and reporting for the SNO Committees. PG&E agrees to consult with the State on the initial members of the reformed SNO Committees, and notes that the SNO Committees already have authority to hire third-party and utility operations experts. (PG&E Brief at 7, 98-99.) TCC "appreciates" PG&E's general agreement with this ACR Proposal. (TCC Reply Brief at 23.)

TURN also generally supports this proposal, with the qualification that the SNO Committees' periodic reporting to CPUC staff should be as transparent as possible, so that other stakeholders could have an opportunity present a potentially different perspective. (TURN Brief at 51.)

The proposal for Expanded SNO Committee Authority is adopted, with the conditions that PG&E will consult with the State on the initial members of the

reformed SNO Committees and PG&E will serve reports summarizing meetings with CPUC staff to stakeholders.<sup>12</sup>

#### **5.1.5. Board of Directors and Holding Company**

ACR Proposal 4 calls for the establishment of additional requirements applicable to the boards of directors of PG&E and PG&E Corp. in the following areas: Composition of the Boards of Directors; establishment of a Safety Subcommittee; Safety Expertise Criteria; and Director Selection Process.

##### Composition of the Boards of Directors

EPUC/IS argues that PG&E's proposed board structure, similar to that proposed by the ACR, does not have an adequate independence or separation between the boards of PG&E and PG&E Corporation and that this is problematic:

There exists an inherent conflict between the interests and fiduciary duties of the PG&E Corporation Board and the interests and fiduciary duties of the PG&E Utility Board. The Utility Board must be able to "operate independently of its Parent Company Board to provide adequate assurance that the Utility is able to meet its safety and reliability requirements and to manage its obligation of providing service at competitive rates." (EPUC/IS Brief at 36.)

EPUC/IS argues that "Without a clear distinction of independence between the two Boards, there is an acute risk that the PG&E Corporation Board will act in a manner to preserve the Corporation over the Utility." (*Id.* at 34.)

MCE makes a similar argument:

To the extent PG&E continues to maintain a holding company structure, the Board of Directors of PG&E Corporation and PG&E Company must reduce their overlap. The current director-sharing paradigm has placed the utility at risk as a result of the holding company inappropriately extracting

---

<sup>12</sup> Initially this can be done via electronic service to the service lists in this proceeding and in I.15-08-019, but can be revised as needed.

value from the Utility, as they propose to do through the PG&E Plan. Preserving separate boards with separate members, until such time as the holding company is consolidated with the utility, will improve the independence of the utility ... (MCE Brief at 45.)

TCC agrees with EPUC/IS and MCE:

The TCC submits that this degree of overlap is inappropriate and should be rejected ... Members of the two Boards have different and sometimes conflicting roles, responsibilities, and duties. To have all the same individuals except PG&E's CEO serve on the Board of both entities would invite conflicts of interest, which could well lead to the subordination of public safety interests to pecuniary interests of the parent company. (TCC Reply Brief at 24.)

PG&E, on the other hand, supports the ACR's proposal that the Boards of the Utility and of PG&E Corporation be largely the same, and argues that the other parties have not shown that there is a conflict between the interests of PG&E Corporation and the Utility, and because the Utility is PG&E Corporation's only substantial asset, "[T]he Utility and PG&E Corporation have a common interest in ensuring that the Utility is financially sound." (PG&E Reply Brief at 65.) PG&E argues that the Commission's Holding Company conditions and Affiliate Transaction Rules – and, in particular, the first priority condition – address these same issues, and that the boards of Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) are structured the same way. (*Id.* at 66.)

While the Commission understands the basis for the argument raised by EPUC/IS, MCE and TCC, and has some appreciation for its underlying point, at this time we see little advantage (and potentially significant problems) with reconstituting the boards of directors to have completely separate membership. The composition of the boards as proposed in ACR Proposal 4 is adopted.

PG&E states that it “is prepared to accept the ACR’s proposal for longer than one-year terms with no term limits,” but expresses “concerns” with the proposal. PG&E’s Board members currently serve one-year terms, which PG&E asserts is “consistent with the consensus of CalSTRS, CalPERS, and other major institutional investors that ‘directors should be accountable to the shareholders they represent and therefore should stand for election every year.’” (PG&E Brief at 107-108.) According to PG&E, if its Board member terms were longer than one year, then PG&E would be legally required to stagger or classify its Boards, which it says institutional investor organizations disfavor. (*Id.* at 108.) While PG&E acknowledges that in the current situation there is potential benefit for greater stability in its boards, PG&E still believes that three-year terms are too long and too different from standard practices. (*Id.*)

TCC agrees with PG&E, and states:

One-year terms for Board members have become nearly universal among public companies and, as PG&E notes, are “consistent with the consensus of CalSTRS, CalPERS, and other major institutional investors that ‘directors should be accountable to the shareholders they represent and therefore should stand for election every year.’” Granting Board members three-year terms would needlessly limit accountability and delay the replacement of poorly performing Board members at a time when highly effective Board members are most vitally needed. This would not be appropriate in light of PG&E’s public safety history and criminal probation. (TCC Reply Brief at 26.)

No party expressed support for three-year board terms. PG&E provided an alternative approach, with two-year terms, with two classes of directors and a phase-out, which it argues would “[S]trike a better balance than three-year terms between the accountability provided by one-year terms, and the stability and

continuity provided by longer terms.” (PG&E Brief at 108-109.) PG&E’s proposed alternative approach is adopted.

PG&E supports ACR Proposal 4’s requirement that “The directors, other than the two executive officers, should be independent directors as defined by the New York Stock Exchange and the Securities and Exchange [Commission],” and notes that its Corporate Governance Guidelines already require at least 75% of the directors to be independent, and PG&E’s current Boards already satisfy the higher threshold set forth in the ACR. (PG&E Brief at 107.) There was no opposition to this proposal. This proposal is adopted.

ACR Proposal 4 requires that at least 50% of directors should be California residents at the time of their selection. PG&E doesn’t directly oppose this requirement, but seeks to condition it with the proviso that: “[T]he Boards would retain flexibility to nominate a slate of directors with a lower percentage if the Boards conclude, and the Governor’s Office agrees, doing so would result in more qualified Boards overall.” (PG&E Brief at 107.)

TURN supports this aspect of ACR Proposal 4, with the additional recommendation that preference be given to candidates who reside in PG&E’s service territory. (TURN Brief at 48.)

TCC opposes this aspect of the ACR proposal, arguing that the Commission should not adopt a strict California residency level for the Board. According to TCC:

Adopting such a quota or requirement may contravene the goals of AB 1054 by according State residency a significance in excess of more important factors, such as an individual candidate’s experience, diligence, talent, and demonstrated dedication to public safety. The Commission should not lose sight of the crucial focus of reform: PG&E must emerge from bankruptcy with a radically transformed governance

structure, attitude, and operational practices that ensure public utility services are provided in a manner compatible with public safety. A California residency requirement cannot be given priority over achieving this result.

As the TCC noted in its Opening Brief, however, there would be value in ensuring that the PG&E Boards include members located in the communities served by, and thus threatened by, PG&E's public safety record. For this reason, the TCC continues to recommend that Commission approval of the Plan be conditioned on the PG&E Board and PG&E Corporation Board each including at least two members who reside in areas served by PG&E. (TCC Reply Brief at 25.)

MCE, on the other hand, argues that every board member should reside not just in California, but within PG&E's service territory. MCE argues that

PG&E's operations have tremendous impacts on the financial wellbeing and safety of its customers. PG&E's recent wildfires and public safety power shutoffs directly affected millions of Californians. To strengthen the incentives for the PG&E board to act in the public interest, they should be required to live in the communities they serve and impact. A director working from another state is not able to truly appreciate what it is like to experience days of smoke exposure, the palpable or realized threat of wildfires, and days without electricity from a Public Safety Power Shutoff. (MCE Brief at 45-46.)

The Joint CCAs have a similar perspective, arguing that the board should be familiar with the on-the-ground circumstances of PG&E's customers, and that the best way for board members to gain independent knowledge of the company's operations is for board members to reside in PG&E's service territory. The Joint CCAs also argue that having board members living within PG&E's service territory could help to insulate the boards from pressures from financial interests that are not aligned with the interests of PG&E's customers and communities. The Joint CCAs recommend that the Commission should require

that “a clear majority” of PG&E’s board members reside in its service territory. (Joint CCA Brief at 21-22.)

TCC, MCE and the Joint CCAs raise valid points. But given the size of California and the somewhat unique issues faced by both California and PG&E, the initial formulation of a minimum of 50% of board members being residents of California, with a preference for those living in PG&E’s service territory, strikes a reasonable balance. This requirement may be revisited if it appears to have a detrimental effect on the quality of the boards.

ACR Proposal 4 additionally states that: “There should be a presumption that the reorganized PG&E and PG&E Corporation boards of directors will be comprised of individuals not currently serving on the boards.”

PG&E strongly opposes this aspect of ACR Proposal 4, arguing that there is no evidence that any of PG&E’s current directors is unqualified to serve, and that PG&E is concerned that a departure of all directors would lead to a loss of continuity and institutional knowledge which could hamper safety and other initiatives. (PG&E Brief at 110.)

TCC counters PG&E’s argument:

PG&E challenges the ACR’s proposed presumption that the reorganized PG&E and PG&E Corporation Boards be comprised of individuals not currently serving on either of those Boards. PG&E asserts that there is substantial evidence of the current Board members’ safety experience and that mass departures would lead to a loss of “continuity and institutional knowledge.” The TCC disagrees.

PG&E has not introduced evidence showing that the current members of both boards have significant and relevant public safety experience. Moreover, PG&E’s claims regarding a loss of continuity and institutional knowledge ring hollow, given that the current Board members have been in place for less than a year. There is no evidence that significant turnover in

Board membership would be detrimental to public safety. What is needed is a thorough house cleaning that helps ensure a transformed PG&E focused on public safety, first and foremost, upon emergence from bankruptcy. (TCC Reply Brief at 26-27, citations omitted.)

TURN takes a middle ground, arguing that: “[D]irectors who were nominated or supported by speculative investor interests drawn to PG&E by its bankruptcy should not serve on the post-emergence Boards.” (TURN Brief at 48.)

PG&E acknowledges that it expects “a substantial change in the Boards in 2020,” and that a number of the current directors will depart and be replaced. (PG&E Brief at 110.) But PG&E believes that some existing directors should be able to continue, and offers that those willing to continue would be vetted against the director skills matrix. (*Id.*) Because ACR Proposal 4 calls for a presumption, rather than a requirement, one way for PG&E to rebut the presumption set forth in the ACR proposal is for potentially continuing board member to undergo a thorough review, equivalent to that of new board members. Accordingly, any potentially continuing board members must be reviewed against the director skills matrix and all other requirements applicable to new board members, including the following criteria set forth in ACR Proposal 4:

In addition to meeting characteristics identified in PG&E’s testimony for the skills matrix, candidates for the boards of directors should be evaluated on the following criteria:

- The character of the candidates and their fit with the board culture such as self-awareness, integrity, ethical standards, judgment, interpersonal skills and relations, communication skills, and ability to work collaboratively with others.
- Possible limitations on serial or “professional” directors, including a restriction on directors that have substantial

relationships with investment funds and investors in PG&E or PG&E Corporation.

- Important public policy objectives such as diversity, representation from regions PG&E serves, and commitment to California's climate change goals.

There was general support for these criteria, although PG&E expressed concerns about the restriction on directors that have substantial relationships with investment funds and investors in PG&E. (PG&E Brief at 101-102.) TCC argues that PG&E overstates the potential impact of these criteria, and that its expressed concerns are baseless. (TCC Reply Brief at 23-24.) TCC is correct, particularly since these criteria are to be used in evaluating candidates, but are not rigid prerequisites to a board appointment. These criteria are adopted as set forth above.

#### Safety Subcommittee

This aspect of ACR Proposal 4 calls for PG&E to constitute a "Safety Subcommittee" of the executive committee of the board of directors, with members having enhanced safety expertise.

PG&E opposes this proposal, arguing that it would be "unnecessary, confusing, and redundant," given that PG&E (based on NorthStar's recommendation) has moved to greater integration of the safety function, PG&E "generally centralizes oversight of all safety issues in the SNO Committees," and PG&E supports ACR Proposal 3 that would expand the SNO Committees' oversight (PG&E Brief at 110-111). PG&E argues that a separate safety subcommittee would be contrary to these efforts, and could create accountability and workload management complications as well. (*Id.* at 111.)

PG&E raises valid concerns, in particular whether a separate safety subcommittee is redundant in light of the expansion of the SNO Committees.

Accordingly, this decision does not adopt the proposal for the establishment of a safety subcommittee.

Safety Expertise Criteria

In this area, ACR Proposal 4 calls for the following:

The skills matrix should include additional criteria that must be met by the Chair of the Board of PG&E, the Chair of the SNO Committees, and at least one other director. Directors who meet one or more of the safety expertise criteria would serve on the Safety Subcommittees. The safety expertise criteria should include the following:

- Specific substantial expertise related to wildfire safety, wildfire prevention, and/or wildfire mitigation.
- Specific substantial expertise related to the safe operation of a natural gas distribution company.
- Specific substantial expertise related to enterprise risk management, including cyber security, and/or experience with nuclear safety (prior to the cessation of production operations of Diablo Canyon Nuclear Power Plant in 2025).

PG&E states that it supports the adoption of safety expertise criteria, and recommends that the criteria be applied more broadly to all members of the SNO Committees. (PG&E Brief at 102-103.) But PG&E then goes on to propose an expansion of the safety expertise criteria to include other elements, including a number that are not directly safety-related, such as expertise related to management of large organizations, and expertise related to utility operations. (*Id.*)

TURN has a more detailed and prescriptive approach, arguing that the Commission should require certain percentages of the board have certain specific expertise, with mandatory Commission review of PG&E's compliance. (TURN Brief at 42-43.)

This Commission neither wants to dilute the meaning of safety expertise nor over-focus on the precise experience held by each individual board member. Accordingly we adopt the proposal as set forth in the ACR, with two modifications: the language relating to the safety subcommittee is removed, and the 2025 expiration of the criteria for nuclear safety is removed, as Diablo Canyon will still have spent fuel storage and decommissioning operations after that date.

Director Selection Process.

ACR Proposal 4 set out a relatively detailed proposal for oversight of the selection of the boards of directors.

PG&E generally supports ACR Proposal 4 on this issue, with the exception of the proposed seven-year sunset date for Commission oversight. Instead, PG&E recommends a sunset at the earlier of (1) five consecutive years in which PG&E has not entered the Enhanced Oversight and Enforcement Process (steps 3 and above); or (2) if PG&E has entered and subsequently exited the Process, PG&E has remained out of the Process for two consecutive years; or (3) the Commission has approved a change in control. (PG&E Brief at 106.)

TURN generally supports the requirements of ACR Proposal 4 in this area, but also wants PG&E's final proposed slate of directors to be subject to a transparent review and approval process, including stakeholder comment. (TURN Brief at 50.)

TCC generally opposes fixed sunset dates for board governance conditions, and argues:

The TCC submits that Board governance conditions should remain in place until such time that the Commission makes a final, non-appealable determination that they are no longer needed to ensure public safety. Any such determination

should be based upon substantial record evidence and subsequent findings that (1) PG&E's culture has changed dramatically, (2) its safety and operational history has been exemplary for such a long period that it is indisputable that it has overcome the strong presumption against it from its past record, and (3) it has controls and other safeguards in place to ensure it does not slip back into old habits. (TCC Reply Brief at 27.)

After considering party comments, this aspect of ACR Proposal 4 is adopted with one minor modification: the seven-year sunset remains in place, but can be extended if PG&E has not met the criteria set forth by TCC.

In addition to the board governance issues raised by ACR Proposal 4, the parties raised additional issues. TURN notes that because of PG&E's holding company structure, PG&E has two almost identical boards, one for PG&E the utility and one for PG&E Corp. the holding company. TURN argues that having two boards instead of one serves no purpose, and in fact results in inefficiencies. (TURN Brief at 43-44.) According to TURN:

An issue that leaps from the record of this case is whether PG&E's current holding company structure serves any useful governance purpose. In fact, the record provides substantial evidence that this structure hinders effective and efficient governance. [...] More importantly, the holding company creates an unnecessarily confusing management structure that results from having two CEOs with an unclear division of responsibility. (*Id.*)

On cross examination, PG&E Corp. CEO Johnson testified:

Q: Well, I feel like I've seen a statistic that 99 percent, or maybe more, of the revenues of PG&E Corporation are actually revenues of the utility. Am I on the right wavelength there?

A: Yeah. I don't know what the exact number is. But that's -- you're on the right wavelength. Yeah.

Q: So in terms of, at least, what produces revenue, the corporation is entirely dependent on -- almost entirely dependent on the utility; is that correct?

A: That is correct today, yes. (Transcript v. 1 at 67.)

TURN questions the value of PG&E's holding company structure, and supports elimination of the holding company, "[U]nless PG&E can make a compelling showing that the Utility and its customers receive material benefits from the holding company." (Ex. TURN-1 at 14.)

According to TURN, PG&E objects to the elimination of its holding company structure on the grounds that while it currently only has a few unregulated subsidiaries, which are inactive, a holding company structure would be useful if PG&E Corporation elects to pursue unregulated businesses. In response, TURN argues that:

In light of the company's dismal safety record, the company should be single-mindedly focused on fixing its safety and competence problems and should not allow itself to be distracted by even considering the pursuit of unregulated businesses. The fact that PG&E's current unregulated subsidiaries are inactive only reinforces that there is no current need for a holding company structure from a governance perspective. (Ex. TURN-1 at 14-15.)

MCE also supports revocation of PG&E's holding company structure, but on different grounds. According to MCE, PG&E has abused the holding company structure:

PG&E's failures to comply with the Commission's holding company requirements, including the first priority condition, and its actions taken to aggressively decapitalize PG&E warrant revocation of PG&E's holding company authorization. This should be done in such a way as to avoid undermining the claims of fire victims that are expected to receive half of their compensation through equity in the holding company. (MCE Brief at 27-28.)

The Joint CCAs support MCE's recommendation that the Commission consider revoking PG&E's holding company structure, arguing that:

[T]he overwhelming bulk of evidence indicates that PG&E's holding company structure is inappropriate to promote the behavior needed to reform PG&E, and has been abused. The Commission should therefore consider revoking PG&E's holding company structure pending evidence of genuine reform. (Joint CCA Reply Brief at 14-15.)

TCC argues that there is inadequate time in this proceeding for the Commission to evaluate the legal and other ramifications of eliminating PG&E's holding company in this proceeding, but the Commission can address that issue in the PG&E Safety Culture OII (OII. 15-08-019), and the Commission should not make any determination in this proceeding that would preclude consideration of the issue in that proceeding. (TCC Brief at 6, 25.) Other parties similarly argue that the Commission should not preclude issues such as this from consideration in the PG&E Safety Culture OII. (*See, e.g.* CCSF Brief at 18.)

In considering the issue of the continued existence of PG&E's holding company structure, PG&E CEO Johnson provided some useful perspective:

Q: Thank you. As a general matter, why -- why would a corporation use a holding company structure?

A: Several reasons. One is for flexibility in pursuing myriad businesses. It gives you some flexibility on the financing options. Those would be the -- the main two.

Q: Given PG&E's current structure and reality where pretty much the only thing in the holding company is the utility, why is a holding company a good idea or appropriate for PG&E?

A: So I think -- I've studied a little history. I think it was created at the time where the desire was to diversify, go broadly, those kind of things. I don't think that's going to happen anytime soon. So that reason for the holding

company, I think, is not particularly strong at the moment. It does give us some financing flexibility going forward here, as we come out of bankruptcy, and so I think it is valuable in that regard.

Q: I notice that some of the debt that's being issued pursuant to the plan is by the holding company. Why is that?

A: So that you can -- you can achieve an appropriate capital structure at the utility, and to do that, and to have investment grade rating on the utility debt, you use -- you'd have to issue some to the holding company.  
(Transcript v.2 at 261-262.)

The plan of reorganization does incorporate significant use of holding company debt. While the operational value of a holding company structure for PG&E at this time is at best questionable, the use of holding company debt under the plan of reorganization does appear to have some cost benefit. Accordingly, the existing holding company structure is left in place for the time being, but the Commission may look again at this issue, taking into consideration PG&E's subsequent safety record.<sup>13</sup> In the meantime, PG&E and PG&E Corporation must continue to notify the Commission of the creation of new affiliates and must promptly file a compliance plan. PG&E must provide quarterly reports to the Commission's Energy Division of the sale or encumbrance of any assets of its affiliates or subsidiaries.<sup>14</sup> Any sale or encumbrance of assets of affiliates or subsidiaries over which PG&E or PG&E Corporation has control and that has a value over \$5 million requires prior Commission authorization. These requirements may be addressed further in I.15-08-019. Those transactions that

---

<sup>13</sup> This issue remains within the scope of the PG&E Safety Culture Investigation (I.15-08-019).

<sup>14</sup> Energy Division may direct that this report be combined with other reports it receives from PG&E.

are proposed in connection with the PG&E Plan approved in this order are approved in Section 5.2 (re financial issues) and not subject to this requirement.

#### **5.1.6. Approval of Senior Management**

ACR Proposal 5 calls for senior management of PG&E to be approved by the safety subcommittee if one is established. Because this decision does not adopt the creation of a safety subcommittee, but instead adopts expansion of the authority of the SNO Committees, this proposal is modified to have senior management of PG&E be approved by the SNO Committee. That approval should come prior to full board approval. PG&E does not object to having the SNO Committee approve the executive officers prior to the full board. (PG&E Brief at 112.) No party opposed this proposal, and it is adopted as modified.

#### **5.1.7. Safety and Operational Metrics**

ACR Proposal 7 calls for the development of safety and operational metrics. Under this proposal, PG&E would propose, in an appropriate proceeding, “[A]ttainable Safety and Operational Metrics that, if achieved, would ensure that PG&E provides safe, reliable and affordable service consistent with California’s clean energy goals.” Because these metrics would be developed in a future proceeding, we do not finalize them here, but rather provide guidance and direction for their development.

Parties were generally supportive of developing metrics, and provided comments that both addressed the process of their development and their potential contents and structure.

Parties addressing the process for developing the metrics had a number of observations and recommendations. MCE supports the establishment of safety and operational metrics to measure PG&E’s success. MCE recommends that the development of the metrics should occur through a transparent process at the

Commission, and PG&E should be precluded from defining the appropriate metrics. According to MCE, if PG&E is allowed to define the metrics, PG&E is likely to set a low bar for defining compliance with the metrics. (MCE Brief at 48-49.)

While TURN supports using appropriate metrics to track and drive PG&E's progress toward improved safety outcomes, TURN warns that: "However, the Commission should not under-estimate the challenge in choosing appropriate metrics." (TURN Brief at 87.) TURN supports having PG&E propose Safety and Operational Metrics in an appropriate proceeding, and recommends that if the metrics will be important to the Commission's assessment of PG&E's safety progress, the Commission should ensure that parties to that proceeding have adequate time for discovery, analysis and comments on PG&E's proposed metrics. (TURN Brief at 88-89.)

In addressing the process for development of the metrics, PG&E asks:

As the purpose of the Safety and Operational Metrics would be to measure PG&E's future progress, PG&E understands, and would request confirmation, that the adopted Safety and Operational Metrics would measure PG&E's performance after the Effective Date, and would not be applied to PG&E's actions before that date. (PG&E Brief at 136.)

While any adopted metrics would be intended to measure PG&E's future performance, the metrics themselves (and the process of their development) could take into consideration PG&E's past performance, such as for the development of performance baselines or other measurement criteria. This issue can be addressed more appropriately in the proceeding to develop the metrics.

Second, PG&E appears to be requesting confirmation of the following:

Given the importance and complexity of defining the Safety and Operational Metrics, PG&E further understands that

Commission approval of such metrics would occur after June 30, 2020, and that such approval is not required for the Commission to approve PG&E's Plan under Section 3292. (PG&E Brief at 137.)

PG&E is correct. We are not adopting or approving metrics here, and doing so is not required for the Commission to approve PG&E's plan of reorganization.<sup>15</sup>

Parties also provided useful recommendations for the substance of metrics that the Commission should keep in mind. TURN provided the following overall guidance and recommendations:

The greater the stakes assigned to metric outcomes, the more care needs to be taken in adopting metrics. For example, if important financial or other outcomes will be determined by the metrics (such as the Earnings Adjustment Mechanism in ACR Proposal 8 or Executive Incentive Compensation), much more care is required, for at least two reasons.

First [...] there is the problem of "managing to the metric," which means that key safety issues that are not addressed by the metrics can get ignored. The antidote to this problem is to adopt a diversity of broad, outcome-based metrics, rather than detailed, focused metrics. Achieving the right portfolio of metrics is challenging, to say the least.

Second, when the stakes are high for the utility, there is greater pressure to manipulate metric results in order to make safety progress look better than it really is. [...] [T]he antidotes for this problem are: (1) objective, not subjective, metrics; (2) clearly defined metrics that do not allow for subjective interpretation; and (3) rigorous audits by the regulators so that utilities know that manipulation will be caught and punished.

---

<sup>15</sup> We note that PG&E is already subject to safety metrics pursuant to its wildfire mitigation plan.

In addition, [...] program targets need to be distinguished from outcome-based (aka performance) metrics. Program targets measure how much work has been performed to meet targets. Assessing progress under targets can be useful, but such measures should not be confused with assessments of safety improvement. Put succinctly, getting work done is not necessarily the same as doing the right work or doing the work right, as has been shown by PG&E's poor safety history. Well-chosen outcome-based metrics are a much better way to assess whether progress is being made in reducing safety risk. (TURN Brief at 87-88.)

TURN is critical of the proposed metrics set forth in ACR Proposal 7, however, as not meeting these criteria, and in some cases not actually constituting metrics. (*Id.* at 89-90.)

Cal Advocates supports the Commission developing organizational metrics for PG&E with the participation of parties. Cal Advocates observes that:

Inadequate metrics can create unintended results and be counter to safety. Current metrics appear to lack leading indicator organizational metrics, key to preventing organizational failure that is the root causes of catastrophic failures. (Cal Advocates Brief at 14-15.)

CCSF also supports the use of operational metrics "that would guide and incent the right behavior and performance by PG&E." (CCSF Brief at 29.) CCSF recommends that adopted metrics should measure and quantify improvements in system performance as part of any work progress metrics (such as tree trimming or poles replacement), and that PG&E's operational and performance metrics should be applied to PG&E's entire system, not just to high fire threat areas. While CCSF understands the need for PG&E to focus on improvements and resource commitments in fire areas, it argues that this should not come at the expense of PG&E's larger system, as old and poorly maintained equipment can fail and cause injuries and property damage anywhere. (CCSF Brief at 29.)

The recommendations of MCE, TURN, Cal Advocates and CCSF are useful, and should be considered in the proceeding that addresses the development of safety and operational metrics. Several parties made additional recommendations for issues to be considered in that proceeding; for example, MCE recommended that the Commission also consider equity and climate outcomes, and CCSF noted that PG&E must plan for emergencies other than fires, such as earthquakes. As TURN notes, the Commission will likely have a full plate just addressing the more narrowly focused safety and operational metrics teed up by the ACR Proposal. Accordingly, while we do not preclude the consideration of other types of metrics in the future proceeding, we do not endorse their consideration at this time.

PG&E makes some requests about the details of the metrics, in essence asking in advance for a determination on the substance of those metrics and their operation. Specifically, PG&E asks that the metrics at issue here “[S]hould not be established in the same manner as other metrics that serve different purposes.” (PG&E Brief at 136.) As examples of metrics that serve different purposes, PG&E cites to executive compensation metrics and the metrics in the Wildfire Mitigation Plans and RAMP [Risk Assessment Mitigation Phase]. PG&E additionally requests that its performance relative to the metrics be measured on an annual basis. (*Id.*) These issues are more appropriately addressed in the proceeding that develops the metrics, and we decline to address them here. The Commission will initiate a new proceeding or a track within an existing proceeding to establish the Safety and Operational Metrics with the input of parties.

### **5.1.8. Fines and Penalties**

The OII and Scoping Memo in this proceeding identified as an issue whether PG&E's plan of reorganization provides satisfactory resolution of claims for monetary fines or penalties for PG&E's pre-petition conduct. (Scoping Memo at 6.)

PG&E argues that it does. According to PG&E, "PG&E has fairly and expeditiously resolved Commission proceedings regarding fines and penalties in a manner that will permit PG&E to emerge from Chapter 11." (PG&E Brief at 65.)

Under PG&E's Plan, the required "CPUC Approval" includes "satisfactory resolution of claims for monetary fines or penalties under the California Public Utilities Code (Public Utilities Code) for prepetition conduct." (*Id.* at 66.) PG&E identifies four Commission proceedings that present claims for monetary fines or penalties. In those four proceedings, PG&E has entered into settlement agreements that would resolve those proceedings upon Commission approval, and the Commission has approved three of them. The one that remains unresolved is the Commission's Wildfire OII (I.19-06-015), but according to PG&E, "The Amended Plan filed March 9, 2020 removes the 'satisfactory resolution' of that proceeding from the CPUC Approval conditions precedent to Plan confirmation but retains it for the Plan Effective Date." (PG&E Brief at 27.) As a result, PG&E says that: "The Commission need not address the final resolution of the Wildfire OII settlement in order to determine in this proceeding that PG&E's Plan meets the requirements of AB 1054." (PG&E Brief at 68.)

TURN objects to this change to PG&E's plan, arguing that "PG&E seeks to put the Commission in an untenable position" of having to approve the plan without knowing whether PG&E will determine that outcome is "satisfactory"

until several months after the Commission has to render this decision. (TURN Reply Brief at 13.) TURN asserts that the outcome of the Wildfire OII is “particularly germane” to the Commission’s approvals under AB 1054. (*Id.*)

As noted above, both the OII and the Scoping Ruling identified as an issue for our determination of whether a proposed plan of reorganization provides satisfactory resolution of claims for monetary fines or penalties for PG&E’s pre-petition conduct. (*Id.*) This is separate from the condition precedent to PG&E’s plan that also requires satisfactory resolution of the Wildfire OII, and thus PG&E’s amendment changing the “satisfactory resolution” date to the Plan Effective Date is not binding on the Commission. Accordingly, we find that PG&E’s plan provides satisfactory resolution of claims for monetary fines or penalties for PG&E’s pre-petition conduct, as the Wildfire OII has been resolved by Commission Decision (D.)20-05-019 issued May 8, 2019.

The only other party to address this issue in briefs was MCE, which makes two arguments. First, MCE cites to language in the plan relating to waiver, release and discharge of claims, and based on that argues:

As a result, the Commission must ensure that it is able to impose and collect all fines and penalties, including with regards to the Tubbs Fire, the Kincade Fire and all other conduct, including unknown conduct that has occurred. As such, the Commission should take protective measures to ensure such fines and penalties, if appropriate, and necessary investigations are not barred after PG&E emerges from bankruptcy. (MCE Brief at 42.)

Second, according to MCE:

Fines and penalties are to be included in the total capped amount of the Fire Victim Trust. This means, without Commission precautions, amounts due from PG&E would actually be taken from fire victims. [...] *The Commission should*

*order PG&E to pay fines and penalties in full without reducing Fire Victims Trust amounts. (MCE Brief at 43, emphasis in original.)*

The Tubbs fire is in the scope of the Commission's Wildfire Investigation proceeding, and accordingly will be resolved (including any fines and penalties) in the proceeding. The relationship between the fines and penalties paid by PG&E, if any, stemming from the Wildfire OII and the amounts paid to fire victims are being addressed in the Wildfire OII and the Bankruptcy Court, and need not also be addressed here.

As to other Commission investigations and proceedings, including but not limited to future investigations and proceedings the Commission may open related to the Kincade Fire or other conduct by the Debtors prior to the effective date of the plan, the plan should make clear that resolution of PG&E's Chapter 11 cases does not preclude the Commission from imposing fines and penalties in any such investigations and proceedings pursuant to its enforcement authority. Accordingly, PG&E is ordered to modify the plan to state that neither confirmation nor consummation of the plan shall affect any pending or future Commission proceeding or investigation, including any adjudication or disposition thereof, and any liability of the Debtors or Reorganized Debtors, as applicable, arising therefrom shall not be discharged, waived, or released.

#### **5.1.9. Regional Restructuring**

In its testimony, PG&E briefly described a proposal to develop a regional restructuring plan that would result in local operating regions led by an officer of the utility that reports directly to the CEO. (Ex. PG&E-1 at 5-35 – 5-36.) ACR Proposal 6 further addresses regional restructuring of PG&E, calls for PG&E to create local operating regions to bring management closer to customers, and calls for PG&E to take two interim steps: appointing regional executive officers to manage each region who report directly to the CEO and President of PG&E, and

for each region to have a risk officer and safety officer that report to the Chief Risk Officer (CRO) and Chief Safety Officer (CSO.)

PG&E generally supports ACR Proposal 6, with some clarifications and qualifications. First, while PG&E supports each region having a non-executive level safety officer, PG&E opposes regional risk officers, as PG&E believes that the CRO should work with “risk owners” with subject matter expertise in each line of business. According to PG&E:

Adding an extra layer of management between the CRO and these risk owners by appointing region-specific risk personnel will detract from the CRO’s ability to ensure consistency across the enterprise regarding the process for evaluating risk, and at best is a redundancy that is unnecessary in light of the CRO’s centralized function. (PG&E Brief at 131.)

TCC supports ACR Proposal 6, noting that while it holds promise of improvements in safety and reliability, it will take years to complete. Accordingly, TCC recommends interim steps be taken, specifically the two steps called for in ACR Proposal 6: appointing regional executive officers to manage each region that report directly to the CEO and President of PG&E, and (2) providing for each region to have its own risk officer and safety officer who report to the CRO and CSO, respectively. According to TCC:

Such interim steps would provide the wildfire victims with peace of mind that what is being done will lead to different results with respect to public safety and that corrections can be made along the way to optimize the Utility’s ability to get to a better, safer, and more affordable system. (TCC Comments at 29.)

CLECA supports regionalization, but notes that given the size of PG&E a regional restructuring program will take time to be developed and implemented

properly. Given that, CLECA has specific recommendations for its implementation:

While developing a regional restructuring plan, PG&E must undertake interim steps to improve its organizational structure and business practices to ameliorate PG&E's interactions with local communities and customers. Based on Ms. Yap's testimony, CLECA recommends the following steps be taken now (importantly, these do not require formal approval of regional restructuring plan and should be readily implementable):

- installation of horizontal linkages across the organization to coordinate across the line activity areas, to ensure that adequate evaluations of safety and reliability elements are conducted in a geographically-based, community-oriented fashion;
- designation of "troubleshooters" to meet directly with community leaders (local government officials, business owners or representatives, and first responders dealing with wildfires) to prioritize local needs and concerns about operations and maintenance practices;
- allowing each Division Manager for select activity areas (Substations, Service Planning, Field Operations, Distribution Control, Field Metering, and Vegetation Management) to set priorities expenditures at the Division level that reflect the safety and reliability needs and concerns of the local communities; and
- using shareholder-funded research to better understand the concerns of ratepayers in various parts of its service territory. (CLECA Brief at 13-14.)

CLECA also suggests that PG&E and the Commission take more time in developing the plan for regional restructuring, so instead of requiring PG&E to file an application with a regionalization proposal by June 30, 2020, CLECA would have PG&E would present it in its 2021 GRC:

CLECA believes that for Regional Restructuring, you want to do it once, you want to do it right, and you don't want to have to do it again. This process should not be rushed while PG&E is focused primarily on Plan confirmation and emerging from bankruptcy. [...] CLECA recommends the following be adopted as a condition of Plan approval:

- PG&E must develop its Regional Restructuring Plan within one year of Plan approval, so that the Regional Restructuring Plan is fully reflected in PG&E's next GRC application. (CLECA Brief at 14.)

While CLECA strongly supports the concept of regional restructuring, and agrees that initial steps in that direction should be taken now, CLECA believes that requiring an application to be filed by June 30, 2020 "[P]recipitously and needlessly rushes the application's development." As CLECA witness Yap testified:

[Y]ou've got 25,000 employees. And you've got a lot of different tasks that those employees are involved. It takes a lot of thought to figure out how you actually are going to break apart what's been centralized back into regional areas. You don't want to do this badly. That will make the problem worse. (CLECA Brief at 26, citing Transcript v.5 at 1019.)

TURN views regionalization as a "worthwhile idea," but raises some concerns similar to those raised by CLECA, specifically that regional restructuring should not be rushed. TURN's proposals for how to implement regionalization differ somewhat from those of CLECA, however. TURN identifies as critical some of the details to be examined, such as:

- (1) the number and boundaries of the regions; (2) how various functions will be allocated and coordinated between central and regional operations; (3) whether the electric and gas operations will have the same or different regions; (4) the cost impacts; and (5) the impact on an already top-heavy management structure. (TURN Brief at 84-85.)

Unlike CLECA, TURN supports the ACR proposal for PG&E to submit an application for approval of a regionalization plan by June 30, 2020, with the caveat that: “[I]f PG&E needs more time to develop a quality and thoroughly considered proposal, it should be given that time.” (*Id.* at 85.)

TURN, however, disagrees with the aspect of ACR Proposal 6 that PG&E should, while its application is pending: 1) appoint regional officers to manage each region, and 2) provide for each region to have its own risk officer and safety officer. TURN believes that these requirements, particularly the first one, may result in PG&E rushing the implementation of its new regional governance structure. According to TURN:

Appointing regional officers to manage each region requires that most of the key details of regionalization be fully determined and implemented, including the challenging task of sorting out which functions will be managed at the central and regional levels and defining new managerial responsibilities. If PG&E is not crystal clear about which managers have responsibility for which functions, TURN is concerned that key responsibilities will fall through the cracks, which can imperil safety.

In addition, TURN believes that the application proceeding will yield important guidance for PG&E regarding how to implement regional restructuring. In fact, the proceeding is likely to result in significant changes to PG&E’s plan. It is not conducive to good management to have PG&E implement one version on the plan when it files its application, only to change key aspects of the plan after the Commission issues its decision. (TURN Brief at 85-86.)

TURN agreed with CLECA witness Yap that the task is large and that, “You don’t want to do this badly. That will make the problem worse. . . . You want to do it once and you want to do it well.” (TURN Brief at 86, citing Transcript v.5 at 1019-1020.)

Accordingly, TURN recommends less of an interim implementation than proposed by the ACR, and recommends more modest interim measures, such as the new regional “troubleshooter” positions proposed by CLECA.

Cal Advocates does not express strong support or opposition to this proposal, but makes two suggestions for implementation. First, that the location of certain California Department of Forestry and Fire Protection (Cal FIRE) Units may be a useful a starting point for how Regional Restructuring could look for PG&E, and second, that PG&E should develop a matrix that explains who reports to who “[I]n a way that minimizes confusion within the utility, so as not to hamper safety, or decrease accountability and transparency.” (Cal Advocates Brief at 14.)

CCSF argues that PG&E has not provided any details on its regionalization plan, making it impossible for parties or the Commission to evaluate its merits, and the Commission should only approve a regional restructuring plan if PG&E can demonstrate that it will “[B]etter enable PG&E to improve customer service and provide safe, reliable and affordable gas and electric services.” (CCSF Brief at 22, 27-28.)

In response, PG&E states that its application:

[W]ill lay out its proposed regions, the governance structure, and categorization of functions as centrally managed, centralized functionally with regional presence, and regionally managed-answering many of the questions posed by intervenors concerning the regionalization proposal. (PG&E Reply Brief at 81.)

PG&E also states that it does not oppose the suggestion that the SNO Committee have a role in approving the delineation of the proposed regions and division of responsibility between localized and centralized operations. (*Id.*) PG&E’s cooperation in this area is appreciated, but CCSF raises a valid point that

the details of regionalization are simply not yet fleshed out. The final approval of the regional restructuring plan will occur in a separate proceeding, not here. In that proceeding, PG&E should be prepared to address the issues discussed above, along with other issues including: regional roles, responsibilities and resource allocation relative to the corporate structure; how the plan will affect various types of customers, including hard-to-reach customers, low-income and disadvantaged communities and communities that have been subjected to wildfire and/or PSPS shutoffs; how best practices will be shared between regions; costs and cost allocation of the plan; identification of services and gas and electric assets that will or will not be regionalized; how PG&E will evaluate the effectiveness of the plan; how regionalization will affect safety and PSPS impacts; and how PG&E will ensure robust communication with its customers in each region. This list is not exclusive and does not circumscribe the scope and focus of the regionalization proceeding, which will be determined in that proceeding.<sup>16</sup>

PG&E is working toward meeting the June 30, 2020 deadline to file its application, and supports taking some interim steps towards regionalization while its application is pending, but with some delay:

PG&E proposes that the interim steps towards implementing regionalization not be taken concurrently with filing the application (presumably on June 30, 2020), but rather that these interim steps begin after the conclusion of wildfire season, likely in the first quarter of 2021. To the extent this is a departure from the ACR's proposal, PG&E believes it is prudent to wait to divide its service territory into the proposed regions, and wait to appoint regional officers and lead safety personnel in each region, until after wildfire

---

<sup>16</sup> In the process of developing their plan PG&E may also want to consult with the other parties that provided comments on this issue.

season so adjustments to the new structure do not pose a distraction to the important work during wildfire season. Based on the current timeline, barring the need for an extension of time owing to the impact of the COVID-19 pandemic, these interim steps would be in place by June 2021. This approach would address CLECA's concern that PG&E could be distracted by reorganization during wildfire season, and affords additional time to flesh out the contours of the regionalization plan between the filing of the application and the actual implementation of interim steps. (PG&E Reply Brief at 82.)

This Commission appreciates CLECA's exhortation that regionalization be done well, but has also lost patience with PG&E's incessant but unfulfilled promises to do better tomorrow. Accordingly, the deadline for PG&E to file its application for regionalization remains June 30, 2020, as proposed. As TURN notes, PG&E may be given the time after filing the application to develop a more thoroughly considered proposal, but we do not accept PG&E's proposal to delay implementation of interim steps for a year. PG&E shall take steps so that by one year from the date of this decision it will be able to appoint regional executive officers to manage each region and report directly to the CEO and President of PG&E, and to appoint regional safety officers that report to the CSO. The remaining implementation schedule, including any interim steps, along with Cal Advocates' implementation proposals and PG&E's argument against the creation of regional risk officers, will be addressed in PG&E's application proceeding.

#### **5.1.10. Enhanced Oversight and Enforcement Process**

ACR Proposal 10 calls for an Enhanced Oversight and Enforcement Process (Process) that sets forth a detailed six-step process that could ultimately lead to the Commission placing conditions on or revoking PG&E's certificate of

public convenience and necessity (CPCN). The introduction to ACR Proposal 10 describes the Process as follows:

The Commission should establish an Enhanced Oversight and Enforcement Process (Process) designed to provide a clear roadmap for how the Commission will closely monitor PG&E's performance in delivering safe, reliable, affordable, clean energy.

The Process contains six steps which are triggered by specific events, some of which would rely on Safety and Operational Metrics. The Process includes enhanced reporting requirements and additional monitoring and oversight. The Process also contains provisions for PG&E to cure and permanently exit the Process if it can satisfy specific criteria. If triggered, the Process would occur in coordination with the Commission's existing formal and informal reporting requirements and procedures and would not replace or limit the Commission's regulatory authority including the authority to impose fines and penalties.

If triggered, the Commission would place PG&E in the appropriate step upon the occurrence of a specified triggering event, with appropriate notification by the Commission's Executive Director, or as otherwise provided below. The Commission's Executive Director may move PG&E through the steps of the Process sequentially, or the Commission or its Executive Director may place PG&E in the appropriate step upon the occurrence of a specified triggering event.

All of the parties that addressed this proposal supported it, but most of them recommended modifications.

TCC points out that:

Under the ACR Proposal, Step 2 Commission Oversight of Management and Operations would be triggered if a "gas or electric incident occurs that results in the destruction of 1,000 or more dwellings or commercial structures and appears to

have resulted from PG&E's failure to follow Commission rules or orders or prudent management practices." Similarly, Step 4 Appointment of Chief Restructuring Officer would be triggered if:

PG&E causes an electric or gas safety incident that results in the destruction of 1,000 or more dwellings or commercial structures and the Commission determines through an Order to Show Cause, Order Instituting Investigation, or other appropriate process, that such event results from the willful misconduct or repeated and serious violations of Commission rules, orders or regulatory requirements.).

In light of PG&E's bad safety history and criminal probation, the Commission needs a significantly more refined and sensitive approach. Specifically, although clearly not the intent, the optics of using the destruction of 1,000 or more dwellings or commercial structures as a triggering event for Commission oversight and management of operations is too high a threshold and sends the wrong message. (TCC Brief at 32-33, emphasis added.)

TCC goes on to argue that:

Destruction of even one or more dwellings or commercial structures should trigger full Commission review, oversight of management and operations and others actions necessary and appropriate to secure public safety. (*Id.* at 33.)

According to TCC, an incident resulting in the destruction of 1,000 or more dwellings or commercial structures that results from the willful misconduct or repeated and serious violations of Commission rules, orders or regulatory requirements should result in the imposition of much stronger consequences, potentially up to the revocation of PG&E's certificate of public convenience and necessity. (*Id.*)

Cal Advocates makes a similar argument:

The Public Advocates Office shares Senator Hill's concern and stresses that the threshold proposed in the ACR for a triggering event leading to Step 2 actions being "the

destruction of 1000 or more dwellings or commercial structures” is too high and that critical failures will be overlooked. The same problem exists with the 1,000 dwellings or commercial structures requirement in Step 4. Events that lead to the destruction of any number of dwellings as a result of utility failings is catastrophic to the families, business owners, and the communities affected. Setting a precise threshold will also allow a utility to operate just shy of failure repeatedly without triggering the next step in the process.

[...]

The threshold for a Commission action triggering event should be set as the diversion from any operational norms that endanger the public, PG&E employees, or the environment due to negligence and/or mismanagement of resources and assets. As currently written, a utility could destroy 999 dwellings or commercial structure each year for three years without the second time becoming a triggering event. (Cal Advocates Brief at 16-18.)

TCC and Cal Advocates are correct – destruction by PG&E of far fewer than 1,000 buildings would be catastrophic and unacceptable. 1,000 is not a magic number, where suddenly the consequences become serious. Instead, the ACR’s use of that number has a different purpose – it delineates an entirely new and additional oversight and enforcement process for the Commission, and does not supplant or preclude the Commission from its continuing enforcement role, including the issuance of Orders to Show Cause and opening of investigations through Orders Instituting Investigations. These remain primary Commission tools for enforcing safety and compliance with the Commission’s General Orders and other rules. The newly created process, however, provides some clarity and certainty to how the Commission will interact with PG&E in a new process that has not been present to date.

TURN correctly points out:

As the ACR explains, the Commission would place PG&E in the appropriate step upon the occurrence of a specified triggering event; PG&E would not necessarily move through the steps sequentially. This Process would supplement the Commission's existing formal and informal reporting requirements and procedures and would not replace or limit the Commission's regulatory authority, including its authority to impose fines and penalties.

If PG&E, through failure to follow Commission rules or orders or through imprudent management practices, destroys one or 25 or 900 houses and structures, the Commission continues to have the ability to take appropriate action, including the imposition of significant fines and other penalties. Accordingly, despite the understandable feelings of dismay that come from considering the potential for PG&E to destroy 1000 buildings, that number will remain as a process threshold in the Enhanced Oversight and Enforcement process that is adopted today.

In addition to its comments on that issue, Cal Advocates makes a number of specific recommendations:

Additionally, the process for exiting Step 2 or moving towards Step 3 lacks public transparency and accountability. Having the items are reviewed by Commission staff and the Executive Director rather than through a proceeding such as an Order to Show Cause or and Order Instituting Investigation frustrates public participation and compromises the Commission's review of the pertinent facts and actions.

**b) Step 3 should be combined with Step 2**

By the time a utility has met the Step 2 criteria (as modified per the recommendation above), the Commission should have appointed a Third-Party Monitor. If a utility has already failed to the point where many homes and businesses have been destroyed, or where systemic failures have not been reported to the Commission, a Third-Party Monitor is warranted (and may in fact be past due). Step 3 must also be

changed to include a requirement for a Third-Party Monitor rather than a Third-Party Monitor being optional and at the discretion of the Executive Director.

**c) Step 5 should come after Step 6**

Prior to consideration of a Receiver, the utility should be subject to the CPCN Review considered in Step 6. Step 5 should occur after Step 6 in the case that the current utility is deemed no longer the appropriate entity to operate in PG&E's current service territory.

**d) Step 5 may require a longer Receivership than 18 months**

The receiver as defined in step 5, will be subject to operating a substantial system for only 18 months. The Public Advocates Office recommends that rather than the current proposal of an 18 month receivership, the receiver should operate over a longer-term as necessary to establish the new entities that will operate in PG&E's current service territory. This will ensure the new entities provide safe and reliable service at reasonable rates. (Cal Advocates at 18-19, emphasis in original.)

TURN, in its Brief, "[S]trongly supports the adoption of a process that provides for additional and increasing operational oversight, including a CPCN review, upon the occurrence of certain triggering events." (TURN Brief at 94-95.)

TURN also proposes a modified version of the ACR's proposed Process:

TURN modifies the ACR proposal to include only actions that the Commission has not previously taken with respect to PG&E. TURN's proposal, presented in full below, essentially collapses the ACR's Process into the following three steps:

- TURN Step 1: Appointment of Independent Third-Party Monitor (ACR Step 3)
- TURN Step 2: Appointment of a Receiver and Chief Restructuring Officer (ACR Steps 4 and 5)
- TURN Step 3: Review of CPCN (ACR Step 6)

TURN has generally incorporated the triggering events included in the ACR proposal as follows:

- The ACR Step 1 & Step 2 “Triggering Events” result in the ACR Step 3 “Action” -Appointment of Independent Third-Party Monitor.
- The ACR Step 4 “Triggering Events” result in the ACR Step 4 & 5 “Actions” -Appointment of a Chief Restructuring Office and a Receiver, respectively.
- The ACR Step 6 “Triggering Events” result in the ACR Step 6 “Action” – Review of CPCN. (TURN Brief at 96.)

TURN’s proposal is quite detailed, and sets forth its proposed triggering events for each step.

MCE also provided relatively detailed recommended modifications, which it summarizes as follows:

MCE recommends that the Commission:

- Expanding the focus of this enforcement beyond safety to include root causes;
- Create a “Step 0” of permanent enhanced oversight to improve transparency, which would include the formation of an Oversight Committee and increased transparency requirements;
- Augment “Step 4” (Chief Restructuring Officer) to also include a Commission appointed examiner;
- Modify “Step 5” to reflect the involvement of the Federal Courts and to ensure that a receiver is broadly empowered to consider all options, including, for example, the sale of the gas business;
- Ensure the availability of “Step 6” (Revocation of the CPCN) in the event of necessity or if other remedial steps are unfruitful. (MCE Brief at 52-53.)

CCSF argues that the process should be strengthened and expedited, and is particularly focused on the potential revocation of PG&E’s CPCN:

The ACR Proposals’ six-step enhanced oversight and enforcement mechanism, while thorough and thoughtful,

would be slow to address safety deficiencies. The Commission should adopt stronger measures, quicker actions, and more consequential outcomes should PG&E fail to meet safety performance standards. In particular, the Commission should expedite the time to initiate a proceeding to revoke PG&E's certificate of public convenience and necessity (CPCN.) (CCSF at 22.)

According to CCSF, the proposed six-step process would take years before the Commission could initiate a proceeding to revoke PG&E's CPCN, and even at that time the Commission would not have investigated options for what would happen if the Commission did revoke PG&E's CPCN. Accordingly:

San Francisco believes that the Commission must begin investigating viable options to ensure continuity of gas and electric service well before the Commission reaches the point where CPCN revocation is a possibility and a different service provider is needed. (CCSF at 30.)

The Joint CCAs and TCC make some more general observations. The Joint CCAs argue that:

In the ACR, President Batjer appropriately seeks a reasonable means to ensure the Commission can act decisively if necessary to ensure public health and safety. To that end, the ACR includes a proposed Enhanced Oversight and Enforcement Process (Process) that would be triggered by specified events, such as a failure by PG&E to obtain an approved wildfire mitigation plan. The Process identifies conditions under which the Commission would take action in response to such triggers, and identifies certain appropriate actions. Certain of the actions that the ACR identifies would be precluded by the moratorium PG&E seeks under Section 1.37(c), including reviewing PG&E's continued eligibility for a CPCN, or placing conditions on its CPCN to ensure safety compliance. Because Section 1.37 would bar the

Commission from taking reasonable actions such as these, it should be rejected. (Joint CCAs at 7-8.)<sup>17</sup>

The “moratorium” potentially created by the former Section 137 (now Section 138) is, according to the Joint CCAs, the following:

PG&E CEO Johnson explains that the “disposition of proposals for certain potential changes to the Utility’s corporate structure and authorizations to operate as a utility” means, to PG&E, “a moratorium on considering those other structural alternatives for at least the proposed initial time period for the Regional Restructuring Plan,” which PG&E proposes to be at least five years or more. (Joint CCA Brief at, footnote omitted.)

While PG&E would like the cited language: “disposition of proposals for certain potential changes to the Utility’s corporate structure and authorizations to operate as a utility,” to result in a five year moratorium, Johnson acknowledged that: “I would like to have five years, but the time will be whatever the Commission says the time will be.” (Transcript v.1 at 83.) On this particular issue, however, the concept of a moratorium is not applicable, as the Enhanced Oversight and Enforcement Process proposal should be understood as superseding the proposal for periodic reviews of PG&E’s CPCN that was raised in raised in I.15-08-019 (PG&E’s safety culture OII).

TCC, in addition to its specific criticisms, makes the more general observation (similar to the one made by TURN, as discussed above) that:

The Commission also must clarify that the Process is a guideline only and will in no way restrict the Commission’s ability to skip steps or take other remedial

---

<sup>17</sup> The Comments of the Joint CCAs refer to Section 1.37(c), but it appears that they actually apply to Section 1.37(b) of the Amended Plan of Reorganization filed with the Commission on February 3, 2020. That same language now appears in Section 1.38(b) of the Amended Plan filed on March 11, 2020.

actions not specified in the Process where circumstances warrant. The Process should not tie the Commission's hands in any way when it comes to the measures that might be needed to ensure public safety. (TCC Brief at 34.)

TCC and TURN are correct; the specified process is not exclusive, and does not limit the Commission's authority to take actions to ensure safe and reliable gas and electric service.

PG&E also proposes modifications to the proposed process. First and foremost is that:

PG&E recommends that, in the Enhanced Enforcement stage of the Process, there should be a minimum time period of 12 months between steps, such that PG&E cannot be moved above Step 3 in the Process based on a failure to implement a corrective action plan before it has had at least 12 months to implement the required corrective actions and the Commission would have a meaningful opportunity to evaluate progress under the corrective action plan. Except with regard to two of the three triggering events for Step 6, the Process proposed in the ACR does not include such minimum time periods. Without them, PG&E might be moved through the higher steps of the Process, up to and including the review of PG&E's CPCN, in a relatively short period of time. (PG&E Brief at 138.)

PG&E, like Cal Advocates, objects to the proposal to delegate to the Commission's Executive Director the authority to move PG&E into and through the Enhanced Enforcement stage of the Process. PG&E notes that under the ACR Proposal, the Executive Director would have the authority to determine whether to move PG&E from a lower step to Steps 3 and 4 of the Process. PG&E believes that this could result in the Executive Director moving PG&E quickly through Steps 3 and 4 without due process. (*Id.*

at 139.) While Cal Advocates believes having review done by staff and the Executive Director frustrates public participation, PG&E raises questions about whether the delegation of authority to the Executive Director as set out in the proposal is appropriately limited to ministerial issues, or whether it extends too far into the area of discretionary decision making. (*Id.* at 139-144.)

In response to the recommendations of Cal Advocates and PG&E, the role of the Executive Director is modified and clarified; instead of having certain determinations that would move PG&E to certain higher steps in the process or allow PG&E to move to lower steps or exit the process be made by the Executive Director, those determinations will now be made via a Commission resolution, as described in more detail below.

Many of PG&E's other recommendations, however, appear to be designed to either slow down the progression of this process or allow PG&E to exit the process entirely. PG&E argues in favor of slowing down the steps of the process:

As described by Mr. Wells, a lack of certainty about the timing of the Enhanced Enforcement process will lead financial market participants to operate under the assumption that PG&E may be moved rapidly through escalating enforcement actions. This assumption will increase the perceived risk of investing in PG&E, with the result that PG&E will find it more difficult to access capital. Likewise, the prospect of accelerated enforcement actions will impact ratings agencies' qualitative views of PG&E's regulatory environment, depressing PG&E's credit rating and leading to a higher cost of debt. (PG&E Brief at 138-139.)

First, we note that PG&E's "regulatory environment" is the same as that of San Diego Gas & Electric Company (SDG&E), Southern California Edison (SCE) and Southern California Gas Company (SoCal Gas), who are regulated by the same agency applying the same laws and regulations. PG&E is receiving greater regulatory scrutiny regarding its safety performance solely because PG&E's safety performance has been so abysmal. If PG&E can show that it can consistently provide safe and reliable service, it will not require such additional scrutiny.

Second, the proposal for enhanced oversight and enforcement provides a defined course of action, with multiple steps, that provides far greater certainty than would otherwise be applicable. PG&E Corp. CEO Johnson readily acknowledged that the Commission has the authority to revoke PG&E's CPCN: "First of all, I don't quibble with the idea that the Commission has the power to review and potentially revoke, with due process, CPCNs." (Transcript v.1 at 83.) Johnson is correct – the Commission can (and has) revoked CPCNs. For example, the Commission revoked the operating authority of 43 telephone corporations in 2010, and another 106 in 2012. (D.13-05-035 at 29-30.) The courts have also found that service territories are not exclusive, and the Commission can accordingly grant CPCNs to competitors of the incumbent:

The policy as declared by the statute and applied by the Commission has never gone to the length of guaranteeing monopoly in all cases, but has at all times deemed the public interest as of paramount importance. It has announced that when an existing utility has fallen short of its full duty to the public it will not necessarily be protected against competition, and that its activities before and at the time competition knocks at the door may be taken into consideration notwithstanding protestations of better behavior in the future. The Commission has never foreclosed itself, even if it could,

from acting favorably on an application for a certificate, the consideration of which is so peculiarly within its own jurisdiction. The discretion of the Commission in such matters is very broad. (*San Diego & Coronado Ferry Co. v. Railroad Com. of California*, 210 Cal. 504, 512-513 (1930).)

The Commission could institute a proceeding now or at any time to determine whether it should revoke PG&E's CPCN. As a practical matter, however, revocation of a CPCN, particularly one of a company the size and nature of PG&E, is a large and complex task, and is not one to be taken lightly or under a tight deadline. The proposal for Enhanced Oversight and Enforcement sets up a methodical, step-by-step system that hopefully will never reach that point, but if it does, it will be in a measured and carefully considered manner.

The Commission appreciates the thoughtful and detailed comments that the parties have provided on this proposal. Taking those comments into consideration, the Commission has modified its proposed Enhanced Oversight and Enforcement process, and adopts a revised version, attached to this decision as Appendix A.

#### **5.1.11. Criminal Probation**

The Commission must consider whether the plan and the resulting governance structure are acceptable in light of PG&E's criminal probation. (Public Utilities Code section 3292 (b)(1)(C).) PG&E's testimony described how it is complying with the terms of its criminal probation, and states that nothing in the reorganization plan is inconsistent with the terms of its criminal probation. (Ex. PG&E-1, Chapter 8.)

In their testimony no party to this proceeding took a clear position either in support or opposition to PG&E on this issue, and no party provided guidance as to how the Commission should apply or evaluate this criteria. The only party that addressed this in any detail in briefs was TCC, which argued that the

Commission should not take off the table or place a moratorium on any of the structural alternatives being considered in PG&E's Safety Culture OII that the Commission might find appropriate to order "[C]onsidering PG&E's criminal probation." (TCC Brief at 6-7.) From this Commission's perspective, the status of the issues being addressed in the Safety Culture OII (discussed further below) does not affect the plan's compliance with PG&E's criminal probation.

While the terms of PG&E's criminal probation include requirements that PG&E comply with Commission orders, there are other terms that are not subject to Commission direction or interpretation. Based on the record before us, and with the conditions and modifications imposed by this order including the adopted ACR proposals, we find no indication that the plan of reorganization and resulting governance structure as approved by the Commission is inconsistent with the requirements of PG&E's criminal probation. Accordingly, the Commission finds that PG&E's plan of reorganization is acceptable in light of PG&E's criminal probation.

## **5.2. Financial**

In this section we consider financial issues relating to the reorganization plan and the resulting governance structure, including ratepayer impacts, PG&E's financial condition, PG&E's proposed securitization, Cost of Capital update, and ACR Proposals on an Earnings Adjustment Mechanism and Executive Compensation.

PG&E states that its financial plan will be funded by a historic amount of new equity and low-cost debt. (PG&E Brief at 31) PG&E requests Commission authorization to issue the following debt:

1. \$11.85 billion in long-term RSA refinanced debt.
2. \$11.925 billion of long-term debt, including:

- a. \$5.925 billion of new long-term debt.
  - b. \$6 billion of temporary utility debt.
3. \$11.925 billion of short-term debt to temporarily finance the exit from Chapter 11 (see bullet 2 above).
  - a. At any time, bullets 2 and 3 in aggregate will not exceed \$11.925 billion.
4. Increase PG&E's post-emergence short-term debt authorization from \$4 billion to \$6 billion. (PG&E Brief at 72.)

In addition to the totl \$23.775 billion long-term debt PG&E is seeking authorization to issue (*see* bullets 1 and 2) and the short-term debt increase, PG&E expects to issue \$9 billion of new equity to fund the plan. (PG&E Brief at 32). PG&E notes that it is seeking authorization for transactions associated with these debt issuances, such as pledging accounts receivable or other credit enhancements. (PG&E Brief at 179-180.)

PG&E's request would result in the issuance of lower cost debt replacing higher cost pre-petition debt as part of the Noteholder RSA, to the benefit of ratepayers. PG&E "anticipates that its post-emergence cost of debt will be significantly lower than the current 5.16% authorized by the Commission in the Cost of Capital Decision." (PG&E Brief at 51.) To implement the lower cost of debt, PG&E proposes to file a Tier 2 Advice Letter within 30 days of the Effective Date of PG&E's Plan. (PG&E Brief at 75.) PG&E's request is granted; PG&E is authorized to issue the requested new debt and equity as described above, including the requested credit enhancements, consistent with its plan of reorganization and working capital and post-emergence short-term debt needs. PG&E is authorized to issue short-term debt post-emergence of \$6 billion, which shall supersede its prior short-term debt authorization. PG&E shall file a Tier 2

Advice Letter within 30 days of the Effective Date of its Plan to implement the debt cost savings associated with the \$11.85 billion Noteholder RSA debt.

### **5.2.1. Neutral, on Average, to Ratepayers**

AB 1054 requires the Commission to determine that the PG&E plan of reorganization is “neutral, on average, to the ratepayers” of PG&E. (Public Utilities Code Section 3292(b)(1)(D).) PG&E argues that its plan satisfies this requirement, as “There are no net increases in rates attributable to PG&E’s Plan (or the associated bankruptcy process).” (PG&E Brief at 3.)

Focusing on currently known costs that could affect rate neutrality, parties identify issues in the plan itself and PG&E’s testimony about specific costs PG&E is seeking or could seek to recover from ratepayers, now or in the future. Parties urge the Commission to exclude certain costs from rate recovery, and further argue that the Commission’s consideration of ratepayer neutrality is not just a one-time snapshot.

For example, TURN identifies four distinct categories of costs it argues the Commission should subject to the “neutral, on average” requirement. TURN observes that while most of the potential costs that could have an impact on rate neutrality are short-term, there are some that potentially extend farther into the future:

Most of the categories of bankruptcy-related costs that are now and will remain subject to the “neutral, on average” requirement of AB 1054 include costs for which the amounts will likely be known at the time PG&E emerges from bankruptcy, or relatively soon thereafter. Such costs would include, for example, bankruptcy-related professional fees, bankruptcy-related financing fees, and pre-petition wildfire claim costs. A fourth category would include costs resulting from PG&E’s bankruptcy that may not emerge until sometime after PG&E’s emergence from bankruptcy, such as higher

costs of debt that PG&E's customers could face if the utility's post-emergence financial condition is less rosy than PG&E predicts. (TURN Brief at 11-12.)

MCE similarly identifies certain categories of costs and calls for the Commission to:

Define the "ground" rules for cost recovery from ratepayers including:

- Prohibiting on an upfront basis certain costs ineligible for ratepayer recovery, including PG&E's bankruptcy costs; and
- Holding PG&E accountable to its clarifications to not recover, at minimum: (1) financing costs associated with Wildfire Fund contributions; (2) bankruptcy related professional fees; (3) equity backstop fees; (4) holding company bridge fees; and (5) 2017 and 2018 wildfire claims costs if the Commission decides to approve the \$7 billion securitization proposal. (MCE Brief at 7.)

MCE requests the Commission keep this proceeding open if it approves the PG&E Plan to ensure it is neutral to ratepayers. (*Id.* at 6). Further, as CLECA puts it: "To meet the intent of AB 1054, "neutral on average" ratepayer standard thus cannot be judged in a single snapshot in time, immediately upon emergence." (CLECA Brief at 17.)

We find TURN's approach useful and address four categories of potential costs associated with the bankruptcy as follows:

- One category of bankruptcy-related costs parties identified is higher costs of debt. Some parties raise arguments that PG&E's underlying assumptions about its future financial outlook are too optimistic and that its debt load is too high. (*See, e.g.* MCE and A4NR.) These arguments overlap with the issue of PG&E's post-bankruptcy financial condition, as the basic idea is that if PG&E's financial condition in the future is worse than PG&E projects, then PG&E's cost of debt will be higher than it otherwise would have been. But

this is an indirect effect stemming from PG&E's future financial condition, including its credit ratings and capital structure. Likewise, while the magnitude of its potential wildfire liabilities led PG&E to decide to file for bankruptcy, the utility must raise capital sufficient to satisfy these claims and pay victims regardless of that decision. Accordingly, these arguments are more appropriately considered under the issue of PG&E's financial condition and capital structure, not under the issue of whether PG&E's plan is neutral, on average, to ratepayers.

- A second category of costs is professional fees relating to the bankruptcy, which was raised in intervenor testimony by multiple parties. In response, PG&E provided a clarification that it will not seek recovery of "bankruptcy-related professional fees," other than those associated with a clearly-defined subset of its overall financing. (TURN Brief at 13, citing Ex. PG&E-8.) Excluding those fees from potential rate recovery is reasonable and is most consistent with both the concept of rate neutrality and the positions of the parties, including PG&E. Accordingly, we determine that PG&E may not seek cost recovery of the costs incurred for professional fees relating to the bankruptcy, and therefore these costs do not implicate the neutral, on average, requirement.

A third source of costs identified by TURN and MCE are financing fees.

As TURN describes it:

PG&E will also incur very substantial amounts of financing fees under its Plan of Reorganization, including items such as equity backstop fees, holding company bridge fees, and new long-term debt issuance underwriting fees. Again, the costs have a very direct nexus to PG&E's "reorganization plan and other documents resolving the insolvency proceeding" and, therefore, are indisputably subject to the "neutral, on average" standard under AB 1054. (TURN Brief at 13-14.)

According to PG&E, its plan provides \$1.4 billion in interest cost savings (or approximately \$700 million in present value<sup>18</sup>) associated with its bankruptcy financing, specifically by refinancing higher cost prepetition bonds at lower rates, with the savings passed on to customers through a reduction in PG&E's authorized cost of debt. (*Id.* at 4.) PG&E asserts that this will actually result in a rate reduction:

The interest cost savings created by PG&E's Plan will translate to rate reductions in the Cost of Capital update following PG&E's emergence from bankruptcy. Based on the Noteholder RSA and anticipated interest rates for the new debt to be issued at emergence under PG&E's Plan, the Utility anticipates that its post-emergence cost of debt will be significantly lower than the current 5.16% authorized by the Commission in the Cost of Capital Decision. Customers will experience a net rate reduction under PG&E's Plan because the interest cost savings exceed the financing fees that PG&E seeks to recover. (PG&E Brief at 51, footnote omitted.)

TURN acknowledges that PG&E clarified that it will only seek to recover in rates:

"[C]ertain financing-related fees associated with the Noteholder [Restructuring Support Agreement] and debt issuance," with an estimated total of approximately \$154 million, to be amortized over the life of the debt. PG&E contends this figure is significantly less than the interest cost savings created by its Plan, such that the net result is a savings for ratepayers. PG&E states that it will not seek recovery of other financing-related fees or costs, such as equity backstop fees, holding company bridge fees, or new long-term debt issuance underwriting fees. (TURN Brief at 14, citing Ex. PG&E-8.)

---

<sup>18</sup> PG&E later states that: "Depending on the discount rate and duration of savings used, the net present value of such savings ranges from approximately \$1 billion to \$683 million." (PG&E Brief at 50.)

Cal Advocates has a similar understanding of PG&E's position on these claims:

PG&E clarified that it will seek to amortize approximately \$154 million in financing related fees over the life of the associated debt instruments, consistent with the recommendation of California Large Energy Consumers Association (CLECA) witness Catherine Yap. With respect to the portion of these financing fees associated with PG&E's Noteholder Restructuring Support Agreement, Yap's calculations show that this amortization begins at \$10.6 million per year and tapers down over time. PG&E should likewise amortize the final fees associated with the remainder of its rate-base debt over the lifetime of the associated instruments. PG&E also clarified that it "will not seek recovery of (1) bankruptcy-related professional fees (except to the extent included within the items referenced in the foregoing paragraph [as relates to specific PG&E debt]); (2) equity backstop fees; (3) holding company bridge fees; and (4) new long-term debt issuance underwriting fees associated with the upfront Wildfire Fund contribution." (Cal Advocates Brief at 10.)

Cal Advocates and CLECA do not object to PG&E's proposal to recover approximately \$154 million in financing related fees, and recommend that PG&E amortize those costs over the life of the debt, which PG&E says is typical and that it proposes to do. (PG&E Reply Brief at 26.)

PG&E argues that the parties that oppose its request to recover the financing fees fail to acknowledge that:

[T]he limited categories of fees designated for recovery either (1) were necessary to achieve the overall savings to customers of the Noteholder RSA; or (2) are typical issuance fees that are recoverable in the normal course of financing transactions..." (PG&E Reply Brief at 27.)

According to PG&E:

PG&E's Plan will create a net decrease in rates, and PG&E's proposal – to transfer interest rate savings to customers, and recover limited financing-related costs which made those savings possible and which would be recoverable in the normal course – is entirely consistent with neutrality under the statute. (PG&E Reply Brief at 28.)

At this time we find that PG&E's proposed recovery of approximately \$154 million financing-related costs for the RSA is consistent with the "neutral, on average, to ratepayers" requirement of AB 1054, based on the projected interest costs savings to ratepayers. At the same time, however, PG&E notes that:

Because certain of the costs that PG&E will seek to recover are associated with transactions that have not yet been consummated (such as the issuance of new debt and potential hedging transactions), the final amounts are not yet known. (PG&E Reply Brief at 27.)

Accordingly, we find that because the Commission needs to ensure that PG&E's request for rate recovery of these costs is neutral, on average, based on the actual total costs incurred, we approve recovery of these costs subject to a condition that PG&E demonstrate they are "neutral, on average" at such time as PG&E requests rate recovery.

The final category of costs relates to PG&E's payments to settle the wildfire claims. A number of parties argued that the Commission should ensure that PG&E does not get rate recovery for the costs of any wildfire claims. Cal Advocates and CLECA, for example, argue for the Commission to preclude PG&E from seeking any rate recovery for wildfire claims costs. (Cal Advocates Brief at 6, CLECA Brief at 18.)

At one point in the proceeding, there appeared to be a potential issue whether PG&E would seek to recover wildfire claims costs separate from its

proposed securitization (addressed below), because PG&E stated that: “If the Commission approves the proposed securitization as requested, PG&E will not seek any other recovery of 2017 or 2018 wildfire claims costs. The Plan is already rate-neutral because the Plan does not propose to recover 2017 or 2018 wildfire claims costs from customers.” (PG&E Brief at 42.)

A number of parties expressed concern that the implication of this language is that if the Commission did not approve PG&E’s proposed securitization, then PG&E would potentially seek rate recovery for 2017 and 2018 wildfire claims costs. For example, TCC pointed out that PG&E stated in testimony that if the Commission does not approve securitization, PG&E may seek rate recovery of 2017/2018 wildfire claims. (TCC Brief at 18.)

Cal Advocates argued that PG&E’s position was an attempt to circumvent AB 1054’s requirement of ratepayer neutrality. (Cal Advocates Brief at 3.)

Subsequently, however, as a result of developments in the Bankruptcy Court proceeding, PG&E modified its position, and stated that:

PG&E’s Plan also is neutral because it does not raise rates to pay for wildfire claims. Even beyond the Plan itself, PG&E will file an application with the Commission for approval of a single post-emergence Securitization of approximately \$7.5 billion which would be neutral, on average, to ratepayers, and also would accelerate deferred payments to the wildfire victim trust under the Plan. If the Commission does not approve the Securitization, PG&E will not seek to recover in rates any portion of the amounts paid in respect of Fire Claims under the Plan. (PG&E Reply Brief at 28, emphasis added.)

Other parties have the same understanding, and concur with PG&E’s statement. (*See, e.g.* A4NR at 2-3.) For example, CUE states:

PG&E’s plan funds the settlement of all wildfire claims through a combination of equity and shareholder-funded debt and PG&E does not seek to recover these costs through its

plan. Rather, after it emerges from bankruptcy, PG&E will apply to securitize some of the debt incurred through the plan but will offset the securitization charges with bill credits so that the securitization is also rate neutral. If the Commission does not approve its securitization application, PG&E will not seek recovery of 2017 and 2018 wildfire costs. (CUE Reply Brief at 5, emphasis added.)

TCC concurs:

In addition, PG&E has now filed its March 23 Motion under which it makes important, additional concessions. Foremost, the TCC noted in its Opening Brief (TCC OB) that because PG&E expressly left open the possibility of seeking rate recovery of costs associated with 2017/2018 wildfire claims in the event the Commission rejected its forthcoming securitization application, the Commission was not in a position to reach a determination on rate neutrality as required under AB 1054. The March 23 Motion has resolved that concern because PG&E has now made a commitment not to file for recovery of costs associated with satisfying claims from 2017 and 2018 wildfires regardless of whether PG&E's forthcoming securitization application is approved. (TCC Reply Brief at 6, citations omitted.)

TURN has the same take on this development, and describes the impact on this proceeding as follows:

The Governor's office has achieved an outcome that removes at least one disputed issue from the table. In its opening brief, PG&E reiterated that it was at least holding open the possibility that, absent securitization, it would seek rate recovery of wildfire claims costs. Under its agreement with the Governor, PG&E now states that even without securitization, it will "not seek to recover in rates any portion of the amounts paid in respect of Fire Claims under the Plan." TURN submits that the Commission should memorialize this commitment in its final decision and make it a condition of Plan approval, just to limit any possibility of future backsliding on this important point. But the issue would no

longer seem to be in dispute among the parties. (TURN Reply Brief at 6.)

PG&E's current position on the issue of the 2017/2018 wildfire claims is that it will not seek cost recovery for wildfire claims *except* in connection with the proposed securitization (and not in the alternative if the Commission rejects it), and the Commission intends to hold PG&E to its promise. Accordingly, the Commission finds that the potential for ratepayers to bear the cost of those claims without nominal cost offsets provided by utility shareholders has been removed from PG&E's reorganization plan. PG&E may not seek cost recovery for wildfire claims except in connection with the proposed nominally offset securitization described in the documents attached to PG&E's March 24, 2020 motion for official notice, and therefore those costs are not a factor in determining if the plan is neutral, on average, to ratepayers.

### **5.2.2. Securitization**

PG&E describes its proposed securitization as follows:

Separate from PG&E's Plan and the plan funding, PG&E contemplates a single post emergence securitization transaction of approximately \$7.5 billion for wildfire claims costs that would be rate-neutral, on average, to customers. The securitization would replace the Temporary Utility debt and is PG&E's preferred path for financing these claims costs in a cost-efficient, rate-neutral, and customer-protective manner. (PG&E Brief at 42.)

Subsequently, PG&E additionally agreed that:

The Securitization includes offsetting credits to be funded initially from a reserve account and further funded with the value of net operating losses contributed in the year in which the net operating losses are utilized. The Securitization structure is anticipated to yield a full (nominal) offset each year to securitized charges. (PG&E Motion for Official Notice, Attachment 2 at 8.)

As described above, PG&E has revised its position on the securitization proposal to clarify that it will not seek cost recovery for the wildfire claims outside of the securitization application. With this revision, the Commission need not review PG&E's proposed securitization in this proceeding. There is now a broad consensus on this approach.

The Joint CCAs state:

As for PG&E's planned securitization transaction, the Commission must consider such proposal pursuant to a separate application. No order in this proceeding should prejudice the Commission's separate review there. A number of parties have discussed aspects of the securitization transaction in this proceeding. However, as PG&E has noted, it will file a separate application seeking approval of its planned securitization transaction. As other intervenors have noted, because the Commission does not have all of the information regarding that transaction in this proceeding, it cannot make reasoned decisions or conclusions at this time. The Commission should therefore defer any analysis or inferences related to that subject for consideration in the appropriate proceeding. (Joint CCA Reply Brief at 11.)

A4NR expresses a similar opinion:

A4NR continues to harbor all of the concerns about the potential securitization voiced in its Opening Brief and testimony, but agrees with the TCC Opening Brief that because "PG&E has thus far chosen not to file its application [for securitization] ... the Commission is left with a myriad of speculative assumptions and uncertainties." [...] Not only is there an inadequate evidentiary record, there is no compelling need for the Commission to prematurely become embroiled in the multiple issues involved in determining whether a yet-to-be-filed Application meets all of the applicable legal requirements for approval. (A4NR Reply Brief at 2-3.)

The question is raised whether the requirements of AB 1054 will apply to PG&E's separate application for securitization. PG&E argues that it does not

apply, focusing on the AB 1054 requirement that ratepayer contributions should be compensated:

Second, the potential ratepayer “risks” of securitization described by certain intervenors do not constitute customer contributions subject to compensation because PG&E’s Plan does not include securitization. The Utility’s proposed post-emergence securitization financing will be the subject of a separate application. In any event, the proposed securitization will recognize customer “contributions” because the Utility proposes to offset the securitization charges with bill credits such that the securitization is rate-neutral on average—even though this approach is not required by AB 1054 because securitization is not part of PG&E’s Plan. (PG&E Brief at 65.)

Other parties disagree with PG&E, and argue vigorously that the requirements of AB 1054 should still apply. CCSF argues:

San Francisco and other parties urged the Commission to subject PG&E’s proposal to securitize \$7 billion of debt it plans to issue post-emergence to the requirements of AB 1054. Despite PG&E’s thin claims that the securitization is not part of the Plan, it is clear from the record that the securitization is essential to PG&E’s Plan. [...] Due to the large amount of debt (at least \$9.4 billion by 2024) that PG&E treats and relies upon as effectively off of the balance sheet of the utility, it is especially crucial for the Commission to carefully consider PG&E’s securitization proposal to ensure that PG&E is not shifting risks and costs to ratepayers in a manner that contravenes the requirements of AB 1054. (CCSF Reply Brief at 3-4.)

TURN, while generally more supportive of CCSF than of PG&E, states that the applicability of AB 1054 to the securitization application does not need to be resolved here:

PG&E also asks the Commission to preemptively declare that any securitization transaction could not implicate the

“contributions of ratepayers” language of AB 1054 because that transaction was not part of PG&E’s Plan. [...] And given that the defining characteristic of the securitization transaction is its assignment to ratepayers cost recovery that, absent the securitization, would fall exclusively on the utility and its shareholders, there would appear to be clear “contributions of ratepayers” warranting compensation under the statute. However, TURN recognizes that the Commission need not determine these issues here, in the absence of an actual fully-developed securitization proposal. (TURN Reply Brief at 28-29.)

Even if TURN is correct that the Commission does not need to make a final determination here of the applicability of AB 1054 to potential future applications, it does not matter for PG&E’s securitization application. The Commission will review the proposed nominally offset securitization application in light of PG&E’s commitments made in its Bankruptcy Court filings, entered into the record here via its March 24, 2020 Motion for Official Notice.

Given the close connection between the plan and the proposed securitization and PG&E’s commitment that its securitization application will meet the requirements of AB 1054, including ratepayer neutrality, the securitization application should satisfy those requirements.

### **5.2.3. Contributions of Ratepayers**

AB 1054 requires that the Commission determine that the reorganization plan recognize the contributions of ratepayers, if any, and compensate them accordingly. (Public Utilities Code section 3292(b)(1)(E).) According to PG&E, its reorganization plan does not require any contributions from its ratepayers. PG&E states:

PG&E has not asked customers to contribute to its Plan via increased rates or otherwise. Wildfire claims will be funded by shareholders and, as described above, PG&E has used the

bankruptcy process to create savings to the benefit of customers and other stakeholders. (PG&E Brief at 63-64.)

TURN argues that the \$2.2 billion of insurance proceeds that PG&E lists as a source of funds for exiting bankruptcy should be considered a ratepayer contribution, since those proceeds were available to PG&E because of ratepayer-funded wildfire liability insurance policies. (TURN Brief at 26.) But TURN goes on to distinguish between currently-apparent contributions that TURN believes should be compensated now from contributions that will emerge over time and will need to be addressed later; under this approach, TURN identifies the wildfire insurance premium expenses of approximately \$500 million that enabled the collection of the \$2.2 billion as a contribution that is apparent at this time. (*Id.* at 27.) CLECA agrees in part with TURN that since the ratepayers bore the underlying costs of the insurance and the insurance proceeds are used in the plan, the ratepayers should be compensated for bearing those underlying costs. (CLECA Reply Brief at 14-16.)

The Commission does not find that ratepayers' payment of the insurance premiums results in a ratepayer contribution under AB 1054; the cost of insurance authorized for rate recovery is a legitimate cost incorporated in rates, regardless of whether a utility has declared bankruptcy, and the argument of TURN and CLECA on this issue is overbroad.

MCE and CCSF take a different approach, and identify future events or transactions, such as PG&E's proposed securitization, that may result in a ratepayer contribution. (MCE Brief at 8-10, CCSF Brief at 5.) TURN also addresses the possibility that future events or actions by PG&E may result in a ratepayer contribution:

For further contributions that will emerge or become more apparent over time, the Commission should establish that

interested parties will have an ongoing opportunity to identify and seek to quantify such contributions, and propose an appropriate mechanism of compensating ratepayers accordingly for such contributions. The Commission may wish to further address this process in a later phase of this OIL, or simply confirm here its expectation that such matters can and should be raised in addressed in future proceedings. (TURN Brief at 27.)

PG&E opposes the idea of ongoing or future review by the Commission on the issue of ratepayer contributions, arguing that because the plan itself does not “require” ratepayer contributions, there is no need for ongoing review by the Commission. PG&E argues that, “As with the neutrality requirement, AB 1054 requires the Commission to determine by June 30, 2020 that the Plan recognizes customer contributions, if any.” (PG&E Reply Brief at 41-42.) According to PG&E, AB 1054 could not have contemplated the ongoing review and evaluation of possible future contributions because that would make it impossible for the Commission to make its determination on this issue by June 30, 2020. (*Id.* at 42.)

The arguments of MCE are CCSF are overbroad while PG&E’s are overly narrow. Application of AB 1054 is neither a single snapshot in time nor an infinitely-applicable standard. To the extent that PG&E may seek a future ratepayer contribution that is clearly connected to the plan of reorganization, the Commission may consider arguments that the requirements of AB 1054 should apply, but we decline to find that AB 1054 creates an ongoing standard of general applicability. For the issues presented in this proceeding, the Commission does not find any contributions of ratepayers that need to be compensated.

#### **5.2.4. Financial Condition and Capital Structure**

As described above, PG&E’s reorganization plan calls for the issuance of significant amounts of new lower-cost debt as well as new equity. PG&E argues

that its plan will enable it to raise the debt and equity needed for it to exit bankruptcy, and provide a clear path after bankruptcy for PG&E to improve its credit rating and maintain access to capital markets. According to PG&E, the plan, by resolving PG&E's major prepetition liabilities and refinancing high-coupon prepetition debt, will restore PG&E to a position of financial health. (PG&E Brief at 36-40.) PG&E states that it is "confident" that as it emerges from bankruptcy it will be able to attract capital and maintain access to capital markets to meet its ongoing operational needs. (*Id.* at 36-37.)

PG&E states that it will emerge from bankruptcy with a balanced capital structure and will be in compliance with the regulatory capital structure authorized in D.19-12-056 if the Commission authorizes a number of adjustments identified by PG&E to include certain items in its equity account and exclude certain charges and debts. (PG&E Brief at 42.) PG&E notes that as an alternative to its proposed adjustments, the Commission could issue PG&E a waiver from compliance with the authorized capital structure, as contemplated in A.19-02-016. (Ex. PG&E-1 at 2-21.) PG&E also points out that its first requested adjustment, exclusion of the shareholder-funded contributions to the Wildfire Fund, is addressed by Public Utilities Code Section 3292(g).<sup>19</sup> (PG&E Comments on Proposed Decision at 11-12.)

PG&E's business plan is based on a five-year projection and includes an assumption that newly-issued long-term debt will be secured debt. Based on its financial assumptions, PG&E projects that it will attain investment grade credit ratings for its secured debt upon emergence. (PG&E Brief at 42.) PG&E has

---

<sup>19</sup> Public Utilities Code Section 3292(g) states with respect to the wildfire fund that "All initial and annual contributions shall be excluded from the measurement of the authorized capital structure."

made various statements to indicate it will seek to improve its credit ratings and underlying credit profile following its emergence from Chapter 11. PG&E states that its contemplated securitization to replace Temporary Utility debt has the potential to improve the utility's credit rating. (*Id.*) PG&E notes that it has "unambiguously committed to expeditiously delivering the Utility after emergence with respect to the \$6 billion of Temporary Utility debt, either through Securitization or through the application of the monetized value of the NOLs [Net Operating Losses]." (*Id.* at 16.) PG&E has also committed that PG&E Corp. will not pay common dividends until it has recognized \$6.2 billion in Non-GAAP Core Earnings, and that amount would be deployed as capital investment or reduction in debt. (PG&E Reply Brief at 16, 34.)

A number of parties note that PG&E's projections for its future financial health are based on assumptions and predictions that may or may not prove to be correct, particularly relating to the amount and cost of PG&E's debt. (*See, e.g.* A4NR, CCSF, San Jose and EPUC/IS.) As TURN puts it: "PG&E's Plan only works if each of a number of very aggressive and optimistic assumptions proves to be correct, not only at the time of emergence from bankruptcy, but for some time to follow." (TURN Reply Brief at 14.)

MCE, for example, criticizes PG&E's request for a waiver of the Commission's capital structure requirement, less because they object to the waiver itself, but more because MCE believes that the request shows that the plan results in insufficient capitalization at the utility. According to MCE, "The PG&E Plan to rely on waivers means they will be financially vulnerable upon their exit from bankruptcy." (MCE Brief at 21-23.)

EPUC/IS agrees that PG&E's plan projects significant improvement in its credit metrics over time but notes that "these projections are the result of forecast

reductions of significant amounts of non-traditional utility debt; *i.e.*, debt that is not used to invest in Utility rate base.” (EPUC Reply Brief at 17-18.)

Some parties primarily just note the potential for adverse impacts if PG&E’s projections prove to be over-optimistic and the utility is overleveraged, such as CCSF, which notes that increased debt leverage can lead to higher ratepayer costs and risks. (CCSF Brief at 10.) TURN also notes that PG&E’s customers could face higher costs of debt if the utility’s post-emergence financial condition is less rosy than PG&E predicts. (TURN Brief at 11-12.)

Other parties propose more specific and detailed approaches, and call for the Commission to strictly condition approval of the PG&E plan. (EPUC/IS Brief at 31; *see also, e.g.* Joint CCAs and CCSF.) One of the more detailed approaches is set forth by EPUC/IS, which calls for the Commission to adopt and enforce a series of specific financial metrics and standards. (EPUC/IS Reply Brief at 13-25.) Noting the commitments in PG&E’s “new updated plan” EPUC concludes that “PG&E must have obligations to prioritize its financial strength improvement that are consistent with its own projections.” (EPUC/IS Reply Brief at 21.) EPUC/IS further contends that the “capital structure waivers requested by PG&E must be backed up by clear and verifiable efforts by PG&E to restore its utility balance of debt and equity capital and eliminate the need for a waiver.” (*Id.* at 23.)

In response to EPUC/IS, PG&E states it “has every intention of doing its best to meet or exceed these projections. Yet future performance ultimately will depend on a variety of factors, including many that are outside PG&E’s control.” (PG&E Reply Brief at 14.)

The parties’ concerns regarding PG&E’s future financial health are not baseless, and this Commission does not have a crystal ball to predict the future.

At this time we cannot say with certainty that PG&E's projections for the future will prove to be correct or how they may prove to be incorrect, and what Commission response may be most appropriate. The resolution of PG&E's application for securitization may also affect PG&E's credit ratings and the amount of time it may need for an ongoing capital structure waiver.

Given this inherent uncertainty, the Commission must keep a close watch on PG&E's financial condition, given its importance for both PG&E and its customers. While we do not adopt the specific proposal of EPUC/IS at this time, there is merit to the underlying idea of the Commission closely monitoring PG&E's actual financial metrics and imposing conditions to ensure PG&E pursues a path to regain its authorized capital structure and reduce its debt burden over time. Accordingly, while acknowledging the uncertainty of predicting PG&E's future financial condition, this Commission approves the financial elements of the reorganization plan. We deny PG&E's proposed adjustments to the calculation of its capital structure except as required by Public Utilities Code § 3292(g), but grant PG&E's alternative request for a temporary waiver from its authorized capital structure, which we find preferable to a hypothetical capital structure. PG&E's capital structure waiver is subject to the following conditions:

PG&E is granted a waiver from its current authorized capital structure for a period of five years from the date of this decision. This waiver applies only to the financing in place upon PG&E's exit from bankruptcy. Consistent with PG&E's plan we expect PG&E to expeditiously pay down Temporary Utility debt over the projected five-year period and regain a closer alignment between aggregate utility debt and the amount of recoverable utility debt. PG&E may seek to achieve this through its securitization application, A.20-04-023 filed April

30, 2020, its commitment to use Net Operating Losses to reduce leverage, its commitment to not pay common dividends for a time, or through other forms of deleveraging it may identify in the future.

In the event PG&E requires an ongoing capital structure waiver beyond the five years granted in this decision, it is directed to file an application that shall include a deleveraging proposal to reduce non-traditional utility debt over time. The application shall include proposals to offset ratepayer impacts associated with an overleveraged capital structure.<sup>20</sup>

PG&E is directed to file a Tier 1 Advice Letter annually following this decision informing the Commission of its current capital structure and deviation from its authorized capital structure, an updated annual forecast for deleveraging, and its current credit ratings for secured and unsecured debt. PG&E will continue to file this Advice Letter annually until directed otherwise by the Commission.

#### **5.2.5. Earnings Adjustment Mechanism**

ACR Proposal 8 is for an Earnings Adjustment Mechanism:

The Commission should consider establishing a mechanism to adjust PG&E's earnings (revenue requirement) based on its achievement of a relevant and reasonably achievable subset of the Safety and Operational Metrics, on a sliding scale of 4 percent up or 4 percent down of earnings in a given year.

Every party that addressed ACR Proposal 8 expressed opposition to attempting to develop and implement it in this proceeding, including TCC, TURN, EPUC/IS, PG&E and Cal Advocates. Among other things, they argue that developing such a proposal and the correct metrics would be complex and

---

<sup>20</sup> For example, a potential mechanism could be to allocate the highest-cost debt to remaining debt associated with the Temporary Utility debt and allocating the lowest-cost debt to the utility recoverable debt.

resource intensive, that the potential benefits are outweighed by the risks (including possible incentives to manipulate data or misplace management focus), and that PG&E could “manage to the metric,” which can lead to unintended negative consequences. (See, TCC Brief at 30-31; TURN Brief at 90-93; EPUC/IS Brief at 37-38; PG&E Brief at 69-70.)

The parties raise valid concerns –unless the incentive and the desired outcome are perfectly aligned, there can be undesirable consequences. Careful development of appropriate metrics that precisely align with the desired outcomes is a necessary prerequisite to the implementation of an earnings adjustment mechanism. Initiating the development of the Safety and Operational Metrics described above is a good first step in that process.

The timeline of this proceeding does not permit even the initiation, much less the completion, of the complex and difficult task of establishing an earnings adjustment mechanism. Accordingly, while the Commission should continue to consider implementing a safety-based earnings adjustment mechanism in the future, either in the PG&E Safety Culture Proceeding (I.15-08-019) or another proceeding, the Commission does not adopt an earnings adjustment mechanism here.<sup>21</sup>

#### **5.2.6. Executive Compensation**

Executive Compensation is addressed in both AB 1054 and ACR Proposal 9. Public Utilities Code Section 8389(e)(4) and (e)(6) state:

- (e) The executive director of the commission shall issue a safety certification to an electrical corporation if the electrical corporation provides documentation of the following:

---

<sup>21</sup> The issue of a safety-based earnings adjustment mechanism remains within the scope of the PG&E Safety Culture Investigation (I.15-08-019).

[...]

- (4) The electrical corporation has established an executive incentive compensation structure approved by the division and structured to promote safety as a priority and to ensure public safety and utility financial stability with performance metrics, including incentive compensation based on meeting performance metrics that are measurable and enforceable, for all executive officers, as defined in Section 451.5. This may include tying 100 percent of incentive compensation to safety performance and denying all incentive compensation in the event the electrical corporation causes a catastrophic wildfire that results in one or more fatalities.

[...]

- (6) (A) The electrical corporation has established a compensation structure for any new or amended contracts for executive officers, as defined in Section 451.5, that is based on the following principles:
- (i) (I) Strict limits on guaranteed cash compensation, with the primary portion of the executive officers' compensation based on achievement of objective performance metrics.
  - (II) No guaranteed monetary incentives in the compensation structure.
  - (ii) It satisfies the compensation principles identified in paragraph (4).
  - (iii) A long-term structure that provides a significant portion of compensation, which may take the form of grants of the electrical corporation's stock, based on the electrical corporation's long-term performance and value. This compensation shall be held or deferred for a period of at least three years.
  - (iv) Minimization or elimination of indirect or ancillary compensation that is not aligned with shareholder and taxpayer interest in the electrical corporation.

- (B) The division shall approve the compensation structure of an electrical corporation if it determines the structure meets the principles set forth in subparagraph (A) and paragraph (4).
- (C) It is the intent of the Legislature, in enacting this paragraph and paragraph (4), that any approved bankruptcy reorganization plan of an electrical corporation should, in regards to compensation for executive officers of the electrical corporation, comply with the requirements of those paragraphs.

In addition, ACR Proposal 9 sets forth nine components that PG&E's executive compensation plan should include:

- Publicly disclosed compensation arrangements for executives;
- Written compensation agreements for executives;
- Guaranteed cash compensation as a percentage of total compensation that does not exceed industry norms.
- Holding or deferring the majority or super-majority of incentive compensation, in form of equity awards, for at least 3 years.
- Basing a significant component of long-term incentive compensation on safety performance, as measured by a relevant subset of by the Safety and Operational Metrics to be developed, as well as customer satisfaction, engagement, and welfare. The remaining portion may be based on financial performance or other considerations.
- Annual review of awards by an independent consultant.
- Annual reporting of awards to the CPUC through a Tier 1 Advice Letter compliance filing.
- A presumption that a material portion of executive incentive compensation shall be withheld if the PG&E is the ignition source of a catastrophic wildfire, unless the Commission determines that it would be inappropriate based on the conduct of the utility.

- Executive officer compensation policies will include provisions that allow for restrictions, limitations, and cancellations of severance payments in the event of any felony criminal conviction related to public health and safety or financial misconduct by the reorganized PG&E, for executive officers serving at the time of the underlying conduct that led to the conviction. Implementation of this policy should take into account PG&E's need to attract and retain highly qualified executive officers.

PG&E presented testimony on its executive compensation structure to show that it complied with the requirements of AB 1054. (Ex. PG&E-1 at 7-1 through 7-23.) A number of parties offered criticism of PG&E's executive compensation program, including TURN, Cal Advocates, SBUA, MCE, and TCC. This section first discusses the statutory requirements, and then turns to ACR Proposal 9.

The requirements set forth in the statute for the structure of an executive compensation plan are detailed and complex. Looking at some of the criticisms and concerns raised by TURN provides some perspective on how challenging a task it will be to properly develop, implement and monitor an executive compensation plan that complies with state law and policy. Among other things, TURN argues that PG&E has not provided enough information regarding the reasonableness of the numerical milestones that establish the threshold, target and maximum levels for each metric; that PG&E's two LTIP [Long-Term Incentive Plan] public safety and reliability 'metrics' are not metrics at all, but rather are what the Commission has called "Program Targets," in that they simply measure how much work PG&E has carried out to meet self-imposed targets, rather than whether that work has met desired safety goals (citing to D.19-05-036); PG&E's proposed STIP [Short-Term Incentive Plan] metrics need more detail and clarity to meet AB 1054's measurable and enforceable

requirements; and PG&E has failed to provide criteria or metrics for reducing or eliminating incentive compensation in response to catastrophic events. (TURN Brief at 68-79.)

TURN would also add four more components to the ACR list:

- Achievement milestones should be calibrated to incent improvement, not provide guaranteed compensation. [...]
- Incentive compensation should be based on outcome-based (performance) metrics, not program targets. [...]
- Metrics on which incentive compensation is based should be measurable, enforceable and objective and not subject to manipulation in ways that undermine the safety purpose of the metric. [...]
- Metrics that encourage reducing customer minutes of PSPS events are warranted to limit the harm to customers from PSPS, and should be balanced by metrics that encourage reducing the number of ignitions that occur in locations and weather conditions that have the highest risk of catastrophic wildfires. [...] (*Id.* at 82.)

The criticisms of PG&E's executive compensation plan raised by TURN and other parties may have merit, but given the schedule of this proceeding, the detail and complexity of the issues, and the need to address executive compensation thoroughly and carefully, we simply cannot adequately review, analyze and resolve in this decision the issues that have been presented.

The question then becomes how to more thoroughly address executive compensation issues. TURN and Cal Advocates recommend that the Commission address PG&E's executive compensation plan in further proceedings. TURN recommends:

The decision in this proceeding should direct PG&E to submit a revised ECP [executive compensation plan]. [...] The revised ECP should direct PG&E to provide workpapers and other supporting documents to show how PG&E derived the

achievement milestones (threshold, target and maximum) for each metric and how achievement of different milestones affects the award of compensation. In addition, for each proposed metric, the Commission should require PG&E to provide complete definitions that prevent subjectivity and manipulation of the results. This revised ECP should be subject to further discovery and record development, perhaps in a workshop. Parties should then be given an opportunity to provide comments on the revised ECP, based on a schedule that allows sufficient time for the necessary detailed analysis and recommendations. (TURN Brief at 83.)

Cal Advocates has a similar, if less detailed, recommendation:

To address PG&E's failure to provide detailed information to demonstrate an effective Executive Compensation program, the Public Advocates Office recommends that resolution of this proceeding include a Commission directive that the Commission keep the Safety Culture Proceeding (I.15-08-019) active and address unresolved ACR Executive Compensation concerns in that proceeding. (Cal Advocates Reply Brief at 6.)

For purposes of this decision, we find that PG&E's executive compensation plan minimally and conditionally satisfies the requirements of Public Utilities Code Section 8389(e)(6)(C), subject to further proceedings before this Commission. The plan will be further strengthened by the adoption of the components of the ACR Proposal 9.

Turning to ACR Proposal 9, parties who commented, including PG&E, TURN, SBUA, MCE, TCC, were largely if not completely supportive. No party opposed the proposal. PG&E agreed to all of the elements of the proposal, with two exceptions, noting that "most of those proposals track the structure PG&E has proposed." (PG&E Opening Brief at 163.) TURN gave qualified or full support for the proposals, further arguing that some of the provisions should be strengthened (for example arguing that the restrictions on severance payments in

the event of a felony conviction of the company should be extended to include any violations of the conditions of PG&E's probation).

PG&E raised concerns with two provisions in the ACR Proposal 9. First, while PG&E supports the presumption that a material portion of executive incentive compensation be withheld if PG&E is the ignition source of a catastrophic wildfire, it argues that PG&E, not the Commission, should determine the applicability of this presumption and whether it should be overcome. PG&E contends that the company's boards will have greater access to information and be better positioned to make this decision. (PG&E Brief at 166-167.)

TCC responds that leaving this decision to PG&E "has not worked well in the past" and would be equivalent to "leaving the fox to guard the henhouse considering PG&E's long and less-than-stellar safety history." (TCC Reply Brief 30-31) TURN proposes a hybrid under which PG&E would make the initial determination as to whether PG&E had caused a catastrophic event that warrants reduction or elimination of incentive compensation, but that this decision would be subject to Commission review and modification. (TURN Reply Brief at 58-59.)

We agree with TURN and TCC. The Commission is in the best position to make an objective determination about whether the utility's conduct justifies a departure from this presumption. It can best balance the interests of promoting safety and properly aligning executive incentives.

Second, PG&E objects to the requirement that its compensation policies include provisions that limit or cancel severance payments for executive officers in the event of certain felony criminal convictions by the company, on the grounds that these restrictions would apply whether or not an executive is

personally liable for criminal misconduct, and would thus undermine its ability to recruit qualified leadership. The provision, however, only applies to a narrow range of the most serious corporate wrongdoing -- felony convictions related to public health and safety or financial misconduct. It also addresses PG&E's concern directly by providing flexibility in its implementation, noting that implementation of the policy should "take into account PG&E's need to attract and retain highly qualified executive officers." TURN would eliminate this flexibility, arguing that "an executive officer who is worried about leading the company into another criminal conviction is one that should not be hired," (TURN Opening Brief at 82.)

MCE, while supporting the ACR, argues that the long-term incentive compensation provision should be changed so that it is based on PG&E's financial health, rather than its financial performance, and that the incentive structure should not use shareholder-focused metrics such as earnings per share. (MCE Opening Brief at 51-52.) However, as PG&E notes, company earnings is a well-developed financial metric that is familiar to utility investors, and is also consistent with the AB 1054 requirement that the executive compensation structure be designed to promote "financial stability."<sup>22</sup> (PG&E Reply Brief 106-107)

As a whole, ACR Proposal 9 will promote public accountability, independent review, and incentives that further the purposes of AB 1054, and should be adopted. In addition to implementing the components of the ACR, PG&E shall provide additional information for the further refinement of its executive compensation plan in the proceeding for the development and

---

<sup>22</sup> Public Utilities Code section 8389(e)(4).

implementation of safety and operational metrics described above, or other proceeding as directed by the Commission.

### **5.3. Climate**

AB 1054 requires the Commission to determine if the plan of reorganization and related documents are “consistent with the state’s climate goals as required pursuant to the California Renewables Portfolio Standard Program and related procurement requirements of the state.” (Public Utilities Code section 3292(b)(1)(D).

In its testimony, PG&E asserts that it has been in compliance with the state’s climate goals, including the Renewables Portfolio Standard (RPS) and procurement requirements, and will continue to do so. More specifically, PG&E points out that its plan of reorganization provides that PG&E will assume all power purchase agreements, renewable energy power purchase agreements, and Community Choice Aggregation servicing agreements. (Ex. PG&E-1 at 9-20.)

Few parties addressed this requirement of AB 1054 either in testimony or briefs. NRDC concurs with PG&E, arguing that PG&E has complied with the state’s climate goals and the requirements of the RPS program, and that the plan is consistent with the state’s climate goals. (Ex. NRDC-1.)

Abrams argues that PG&E’s plan is an inadequate response to climate change, and that: “The plan must provide measurable climate change adaptation metrics in-line with California’s climate goals and tied to PG&E bottom-line financial metrics.” (Ex. Abrams-1.) Abrams provides no detail in his testimony about how to do that, but generally seems to be focused on wildfire risk mitigation, rather than the statutory criteria. Abrams’ brief reiterates the idea that the plan of reorganization must effectively address wildfire mitigation in order to be consistent with the state’s climate goals. (Abrams Brief at 8.)

Next Era believes that the plan of reorganization is consistent with the state's climate goals:

To be consistent with the state's climate goals as required by PU Code Section 3292(b)(1)(D) as well as the RPS and related procurement requirements, the PG&E Plan and the Commission's approval of the PG&E Plan must ensure that PG&E assumes all of its PPAs. The PG&E Plan and PG&E's testimony indicate that this will occur. (Next Era Brief at 3.)

In contrast, the Joint CCAs argue that PG&E does not even need to engage in electric procurement in order to achieve the state's climate goals. (Joint CCA Brief at 14-15.)

And TCC states: "The TCC submits that the effects of PG&E's Plan are consistent with California's climate goals and related California procurement requirements." (TCC Brief at 7.)

Given that PG&E's plan of reorganization will maintain its existing renewable energy power purchase agreements, and that its obligations under the RPS are ongoing and remain subject to the authority and direction of the Commission, the plan of reorganization satisfies the statutory requirement that it be "consistent with the state's climate goals as required pursuant to the California Renewables Portfolio Standard Program and related procurement requirements of the state." (Public Utilities Code section 3292(b)(1)(D).

#### **5.4. Quality of Service and Quality of Management**

The Commission is considering whether PG&E's plan of reorganization will maintain or improve the quality of service to PG&E ratepayers, and whether the plan will maintain or improve the quality of management of PG&E. Given PG&E's recent past quality of service and management, PG&E needs to do more than maintenance, and an improvement in quality of service is necessary. Between the effort and recommendations of PG&E and the other parties and the

proposals set forth in the ACR, it appears that the plan of reorganization has the potential to improve both the quality of service to PG&E ratepayers and to improve the quality of management of PG&E. The Commission will consider metrics to measure PG&E's quality of service and quality of management in the proceeding addressing Safety and Operational Metrics described above.

### **5.5. Employees and Communities**

In evaluating the plan of reorganization the Commission is also considering the effects of the plan on PG&E employees and local communities.

As to employees, the Commission needs to consider whether the plan is fair and reasonable to affected PG&E employees. PG&E argues that:

PG&E's Plan is also fair to PG&E's employees, because it provides for the assumption of various existing agreement with union and non-union employees, including collective bargaining agreements and the employee benefit plans governing employees. PG&E's Plan also incorporates an agreement with the International Brotherhood of Electrical Workers (IBEW) to extend and enhance the IBEW collective bargaining agreements for the benefit of those employees, as well as the overall enterprise. (PG&E Brief at 176, citing to PG&E testimony, footnotes omitted.)

CUE agrees. According to CUE: "Undisputed record evidence shows that PG&E's plan is fair and reasonable to employees." (CUE Brief at 3.) CUE cites to the many problems that PG&E has had (even beyond the safety issues discussed above), and their effect on employee workload and morale, and argues that the elements of the plan of reorganization positively address those: "It is because of this history that PG&E's commitments in its plan of reorganization to a four-year extension of the contract with an annual wage increase, stable healthcare costs and job security, are essential to employees." (CUE Brief at 4.)

No party made an argument opposing the position of PG&E and CUE. Based on the record, the Commission finds that PG&E's plan of reorganization is fair and reasonable to PG&E employees.

In general, there does not appear to be much in the reorganization plan that would specifically and directly affect local communities differently than it would affect the whole of PG&E's service territory, except for one proposal. The aspect of the proposed reorganization of PG&E that could have an effect on local communities is the proposal for regional restructuring or regionalization, which is discussed in more detail above.

City of San Jose notes that the regionalization proposal is not detailed enough to determine if it would be beneficial to local communities. (San Jose Brief at 18-19.) CCSF makes a similar argument as well. (CCSF Brief at 27-28.) While San Jose and CCSF are correct that both PG&E's testimony and ACR Proposal 6 require further development, based on the limited record before us it appears that regionalization has the potential for a beneficial effect on local communities by providing a management structure that is more directly connected (and hopefully more responsive) to local communities. Based on the record, regionalization does not appear likely to have an adverse effect on local communities, and as discussed above, it is worthwhile to further develop the proposal. We do not find anything in the plan that would be uniquely detrimental to local communities, and the regionalization proposal has the potential to benefit local communities.

## **5.6. Commission Bankruptcy Costs**

PG&E is ordered to reimburse the Commission for payment of the fees and expenses incurred by the Commission for its outside counsel and financial advisor for services rendered relating to the chapter 11 cases, related proceedings

and associated financings. As with other professional fees associated with the bankruptcy proceedings, PG&E similarly may not seek cost recovery of the Commission's costs for such fees and expenses, consistent with AB 1054's requirement that the plan be "neutral, on average, to ratepayers."

### **5.7. Other Proposals and Related Proceedings**

A number of parties made additional or unique proposals for the Commission to consider in this proceeding.

The Joint CCAs recommend that the Commission develop a plan to phase out PG&E's retail electric generation service to customers, including associated procurement activities, by 2025. (Joint CCA Brief at 10-15.) As the Joint CCAs note, this issue would more appropriately be addressed in the PG&E Safety Culture OII (I.15-08-019). Accordingly, the Commission need not and does not address this recommendation here.

CCSF requests that the Commission require PG&E to undertake asset sales in order to improve its financial condition. CCSF believes that this should be done in the PG&E Safety Culture OII or another proceeding. (CCSF Brief at 4.) Accordingly, the Commission need not and does not address this request here.

CEERT argues for adoption of an alternative structure for PG&E's electric distribution function, and specifically proposes that PG&E's distribution service should be restructured as an Open Access Distribution System Operator. (CEERT Brief at 6-7.) Again, this proposal was previously made in the PG&E Safety Culture OII, and would more appropriately be addressed there, and accordingly is not addressed here.

These arguments are essentially asking that issues be preserved in the PG&E Safety Culture OII, and are opposing PG&E's request for a "moratorium" on the Commission's consideration of issues in that proceeding. That

moratorium is focused on the most recent proposals presented in that proceeding, which are: 1) Separating PG&E into separate gas and electric utilities or selling the gas assets; 2) Establishing periodic review of PG&E's Certificate of Convenience and Necessity (CPCN); 3) Modification or elimination of PG&E Corp.'s holding company structure; and 4) Linking PG&E's rate of return or return on equity to safety performance metrics. (*See, e.g.* Ex. PG&E-1 at 1-9 – 1-10.) Those proposals were presented in a ruling in that proceeding issued on June 18, 2019, with party comments and reply comments filed in July and August 2019. The PG&E Safety Culture OII has largely been on hold since that time as a result of PG&E's bankruptcy.

The above parties are not alone in opposing PG&E's request for a moratorium. As TCC argues:

The Commission should reject PG&E's repeated request that the Commission determine that it will not be forced to sell its gas business, eliminate its holding company, municipalize, or have its certificate of public convenience and necessity (CPCN) reviewed or modified (except as provided in connection with the Enhanced Regulatory Oversight and Enforcement Process proposed in the ACR). The TCC agrees with other intervenors that the Commission's order on the Plan should not take off the table any options being considered in the Safety Culture OII (15-08-019) or, for that matter, in other or future Commission proceedings, including the possibility of ordering any other structural changes to PG&E. In fact, the CPUC should explicitly retain jurisdiction and authority to make whatever changes it finds necessary or appropriate at any time, given PG&E's far from satisfactory public safety record. This is nothing unique or unusual; as Commission knows, a basic tenet of regulation is that the Commission can neither bind itself nor future Commissions. *Order Instituting Rulemaking to Evaluate Telecommunication Corps. Serv. Quality Performance & Consider Modification to Serv. Quality Rules*, No. D.18-10-058, at 22 (CPUC Oct. 25, 2018)

(“the Commission cannot bind itself to act in a certain manner in the future”). This tenet is particularly compelling in this instance where PG&E has yet to bring major components impacting its Plan and its future, as well as the future impact on ratepayers and the citizens of Northern California, to the Commission (*i.e.*, the Regional Reorganization Plan and its application for securitization). Likewise, there are issues that simply cannot be fully aired under the time constraints imposed by AB 1054.

PG&E is in no position to be making demands, and the Commission should not take off the table, or place a moratorium on, any of these tools that it might ultimately find appropriate to order in light of PG&E’s “safety history, criminal probation, recent financial condition, and other factors deemed relevant by the Commission.”

Section 3292(b)(1)(C). By expressly holding that its approval of the Plan is subject to, and without prejudice to, any reforms the Commission might choose to order in the Safety Culture OII (including structural reforms) and other proceedings, the Commission can make the findings required by Section 3291(b)(1)(C), without first making a final determination as to the necessity of any of those reforms. (TCC Reply Brief at 13-14, citation omitted.)

TCC is correct, and this Commission declines to place a moratorium on the exercise of its own authority to regulate PG&E. The disposition of at least some of the four proposals identified by PG&E have been addressed previously in this decision, but for clarity’s sake we will summarize that disposition here.

1) Separating PG&E into separate gas and electric utilities or selling the gas assets: in June of 2019 the Commission was interested in exploring this idea, but it is less of a priority today, particularly in light of the pending regionalization. Whether or not this proposal remains within the scope of the PG&E Safety Culture OII will be determined in that proceeding. 2) Establishing periodic review of PG&E’s CPCN: this proposal has been superseded by the proposal for

the Enhanced Oversight and Enforcement Process, and will be taken out of the scope of the PG&E Safety Culture OII. 3) Modification or elimination of PG&E Corp.'s holding company structure: this issue was presented in this proceeding and remains a live issue within the scope of the PG&E Safety Culture OII or other appropriate proceeding. 4) Linking PG&E's rate of return or return on equity to safety performance metrics: this issue was presented in this proceeding and remains a live issue within the scope of the PG&E Safety Culture OII or other appropriate proceeding. This is the Commission's "disposition of proposals for certain potential changes to the Utility's corporate structure and authorizations to operate as a utility," under Section 1.38 (Section 1.37) of the Amended Plan of Reorganization.<sup>23</sup>

## **6. Comments on Proposed Decision**

The ALJ's proposed decision was mailed to the parties in accordance with Section 311 of the Public Utilities Code, and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by TCC, Solar Energy Industries Association, San Jose, A4NR, EPUC/IS, Joint CCAs, TURN, CLECA, Wild Tree Foundation, CEERT, SBUA, PG&E, CCSF, SSJID, MCE and Cal Advocates. Reply comments were filed by CLECA, EPUC/IS, A4NR, CUE, Cal Advocates, Joint CCAs, TURN, Valley Clean Energy Alliance, PG&E, American Wind Energy Association of California, CCSF, TCC, San Jose and SBUA.

TCC argues that the language of the proposed decision granting PG&E a waiver of its authorized capital structure should be modified to clarify that the waiver is limited, and applies "[O]nly to the extent necessary to implement

---

<sup>23</sup> The Commission similarly declines to place a moratorium on the exercise of its authority on additional matters beyond the four specific issues addressed above.

specific provisions of the Plan that have been reviewed and approved by the Commission and the Bankruptcy Court.” (TCC Comments at 13.) MCE supports TCC’s recommendation. (MCE Comments at 7.) TCC and MCE are correct that the waiver is limited, and not general. The corresponding language has been modified to reiterate this clarification.

CEERT expresses concern that while the proposed decision generally rejects PG&E’s proposed “moratorium” on certain Commission actions, the Commission’s adoption of a regional restructuring plan might result in a moratorium on proposed changes to PG&E’s safety and governance structure that are still pending in I.15-08-019. (CEERT Comments at 3-6.) To clarify, the Commission’s adoption of a regional restructuring plan does not directly or indirectly approve or otherwise result in a moratorium on Commission action or otherwise limit the Commission’s authority.

A number of parties argue that the reorganization plan should be modified to increase the amount of equity issued by PG&E from \$9 billion to \$12 billion, with a corresponding reduction of \$3 billion in debt to be issued by PG&E Corp. (San Jose Comments at 6-7; A4NR Comments at 6-8; EPUC/IS Comments at 11-12; TURN Comments at 13-14.) These parties argue that the additional equity is available under PG&E’s equity backstop commitment letters, and that this approach would reduce PG&E’s debt load. PG&E responds that the equity backstop commitment letters do not support the proposed modification, and accordingly the argument is incorrect. (PG&E Reply Comments at 1.)

Contrary to what the non-PG&E parties suggest, increasing the amount of the equity backstop commitments to \$12 billion from \$9 billion is not consistent with the terms of the backstop commitment letters approved by the Bankruptcy Court, and would require the agreement of the parties to those letters. There is

nothing in the record to show that such agreement has been obtained or would be obtainable. In addition, such a major revision to the financing structure at this late date would also likely be disruptive to the procedures of the Bankruptcy Court. Given the scant record support for the proposal and the potentially significant other problems it could cause, the proposed decision is not modified to increase the amount of equity to be issued.

Several parties wanted language to make clearer or stronger the finding that PG&E will not seek cost recovery for the 2017/2018 wildfire claims except via the proposed securitization. (*See, e.g.* Cal Advocates Comments at 5-7.) While the proposed decision appears to be clear on this point, additional language to this effect has been added to the decision.

PG&E requests clarification whether the language in the proposed decision requiring “approval from the State” for the appointment of directors is referring to the Governor’s Office or the Commission. (PG&E Comments at 2-3.) To clarify, the phrase “approval from the State” on this issue refers to the Governor’s Office, not the Commission.

PG&E raises practical concerns relating to the proposed decision’s requirement that it obtain Commission authorization for the formation of any affiliates or subsidiaries, or for the sale or encumbrance of any assets of its affiliates or subsidiaries. (PG&E Comments at 4-5.) EPUC/IS opposes most of PG&E’s requested changes, and argues that the Commission should retain oversight of PG&E’s formation of affiliates and subsidiaries as it exits bankruptcy. (EPUC/IS Reply Comments at 5.) This requirement has been modified to only require reporting of most such transactions, and it does not apply to transactions that are proposed in connection with the PG&E Plan approved in this order.

PG&E states that it is committed to regional restructuring, and intends to file its application by the June 30, 2020 date set in the proposed decision, but observes that:

It is not practical, however, for PG&E to appoint any of the regional vice presidents or regional safety leads by June 30. The search for such leaders is not a rapid process in any circumstance, and the challenges in recruiting qualified individuals are magnified at this time due to the COVID-19 pandemic, the pendency of PG&E's Chapter 11 Cases, and the inchoate nature of the positions to be filled. It is important that PG&E identify the right people and not rush the process simply to meet a June 30 deadline. In addition, it is difficult, if not impossible, to appoint the regional leaders before the Commission and stakeholders have a chance to review the proposed regions. (PG&E Comments at 7.)

PG&E raises a valid point, particularly since the Commission wants to ensure that the regionalization is executed with care, and with attention to the structures that are put in place. TURN agrees with PG&E on this point. (TURN Reply Comments at 2-3.) Accordingly, the deadline for PG&E to appoint its regional vice presidents and safety leads is extended to one year from the date of this decision.

SBUA calls for the Commission to impose more specific requirements on the details to be addressed in PG&E's application for regional restructuring. (SBUA Comments at 8-10.) SBUA's request builds upon a similar request made earlier in the proceeding by CCSF. (*See*, CCSF Brief at 27-28.) The scope of the issues to be addressed in PG&E's regionalization application will be determined in that proceeding, not here. But without limiting the scope of that proceeding, the proposed decision has been modified to provide guidance as to at least some of the issues that the Commission will likely want to ensure are addressed in that proceeding.

PG&E notes that the proposed decision does not accurately reflect the proposal that it adopts regarding the timing of the filing by PG&E of an advice letter to update its cost of debt. (PG&E Comments at 9-10.) PG&E's proposal was for an advice letter to be filed "within 30 days of the Effective Date of PG&E's Plan" (which is the date of PG&E's emergence from bankruptcy), but the proposed decision, while stating that it is granting PG&E's request, instead directs that the advice letter is to be filed "30 days after the effective date of this decision." (*Id.*) This language has been corrected.

PG&E requests clarification regarding PG&E's plan to pledge the common stock of the Utility as collateral for a subset of new debt the parent will borrow as part of the Chapter 11 exit financing. (PG&E Comments at 10.) PG&E pointed out that the proposed decision did not address this issue, and requests that the Commission determine that the pledge by PG&E Corp. of its ownership interest in the utility as collateral for the debt does not require Commission approval, or to grant approval if required. (PG&E comments at 10.) A4NR opposes PG&E's request, and requests that PG&E be required to file an application seeking approval of terms of PG&E Corp. debt that "could affect utility resources." (A4NR Reply Comments at 1-2.) TURN observes that other parties raised arguments opposing PG&E's request. (TURN Reply Comments at 4-5.) To clarify, we determine that Commission approval is not required for the pledge of utility stock at this time, but we remind PG&E that in the event of a default in which any lender seeks to acquire or control PG&E, Commission approval is required pursuant to Public Utilities Code Section 854. Public Utilities Code Section 701.5, which applies to the utility, is not implicated by the parent holding company's pledge of utility stock as collateral for the secured debt issuance under consideration here.

PG&E also requests that we consider how provisions adopted here on future affiliate and subsidiary financial transactions would apply to components of its bankruptcy exit financing, especially those concerning accounts receivable. We clarify that approval is given for the components of the bankruptcy exit financing described by PG&E, including those relating to accounts receivable.

PG&E also seeks clarification that the Tribal Land Transfer Policy issued by the Commission on December 5, 2019 and the draft Guidelines published by Commission staff do not restrict the contemplated grant of encumbrances under the financings authorized in this decision. (PG&E Comments at 11.) Specifically, PG&E expressed concern that term “encumbrance” in the draft Guidelines implementing the Tribal Land Transfer Policy creates some uncertainty that could undermine the secured debt transactions the Commission is authorizing. To reduce uncertainty, the Commission does not require application of the guidelines of the Tribal Land Transfer Policy to the authorized financing, including any security interests granted in connection with such transactions.

SBUA notes that the proposed decision, in addressing PG&E’s quality of service and quality of management, does not impose any additional going-forward requirements in these areas. (SBUA Comments at 12-15.) While we do not put in place SBUA’s requested measures, we will modify the proposed decision to implement a necessary first step, which is to consider metrics to measure PG&E’s quality of service and quality of management.

Some parties note that the decision’s findings of fact, conclusions of law and/or ordering paragraphs are not as detailed as the text in the body of the decision, and argue that unless the findings and conclusions and ordering paragraphs are expanded to match the body of the decision, there is a risk that

the decision does not actually bind PG&E. (*See*, CLECA Comments at 8; al Advocates Comments at 6-7.) This concern is misplaced. PG&E must comply with all language in a decision, not just the ordering paragraphs. PG&E can be penalized if it “[F]ails or neglects to comply with any part or provision of any order, decision, decree, rule, direction, demand, or requirement of the commission...” (Public Utilities Code section 2107.)<sup>24</sup> For an example in this proceeding, the body of this decision states: “PG&E may not seek cost recovery for wildfire claims except in connection with the proposed nominally offset securitization described in the documents attached to PG&E’s March 24, 2020 motion for official notice.” PG&E must comply with this language regardless of its specific location within the decision.

Many comments either reiterated arguments previously made and considered, or raised issues outside the scope of the proceeding. No changes to the proposed decision were made in response to these comments.

## **7. Assignment of Proceeding**

Marybel Batjer is the assigned Commissioner and Peter V. Allen is the assigned Administrative Law Judge in this proceeding.

## **Findings of Fact**

1. PG&E’s reorganization plan and other documents resolving the insolvency proceeding, including PG&E’s resulting governance structure, are acceptable in light of PG&E’s safety history.

---

<sup>24</sup> Public Utilities Code Section 2107 reads: Any public utility that violates or fails to comply with any provision of the Constitution of this state or of this part, or that fails or neglects to comply with any part or provision of any order, decision, decree, rule, direction, demand, or requirement of the commission, in a case in which a penalty has not otherwise been provided, is subject to a penalty of not less than five hundred dollars (\$500), nor more than one hundred thousand dollars (\$100,000), for each offense. (Emphasis added.)

2. PG&E's reorganization plan and other documents resolving the insolvency proceeding, including PG&E's resulting governance structure, are acceptable in light of PG&E's criminal probation.

3. PG&E's reorganization plan and other documents resolving the insolvency proceeding, including PG&E's resulting governance structure, are acceptable in light of PG&E's recent financial condition.

4. PG&E's reorganization plan and other documents resolving the insolvency proceeding, including PG&E's resulting governance structure, are acceptable in light of other factors deemed relevant by the Commission.

5. The Commission has determined that the reorganization plan and other documents resolving the insolvency proceeding are consistent with the state's climate goals as required pursuant to the California Renewables Portfolio Standard Program and related procurement requirements of the state.

6. The Commission has determined that the reorganization plan and other documents resolving the insolvency proceeding are neutral, on average, to the ratepayers of PG&E.

7. The Commission has determined that the reorganization plan and other documents resolving the insolvency proceeding recognize the contributions of ratepayers, if any.

8. PG&E has established an executive compensation structure for any new or amended contracts for executive officers, with additional requirements imposed by ACR Proposal 9.

9. Some issues raised in this proceeding are more appropriately addressed in I.15-08-019 or other proceedings.

10. Some of the proposals made in this proceeding will require additional analysis, development and refinement prior to implementation.

11. The Commission may have pending or may institute other investigations and proceedings against the Debtors arising from Debtors' conduct prior to the effective date of the plan, including but not limited to those involving the Kincade Fire.

12. Regional restructuring of PG&E has the potential to improve safety and responsiveness to local communities.

13. An Enhanced Oversight and Enforcement process for PG&E will add clarity and certainty to the Commission's processes for monitoring and enforcing PG&E's safety performance.

14. PG&E's reorganization plan calls for PG&E to issue long-term and short-term debt.

15. The Commission incurred fees and expenses for its outside counsel and financial advisor for services rendered relating to the chapter 11 cases, related proceedings and associated financings.

### **Conclusions of Law**

1. PG&E's reorganization plan and other documents resolving the insolvency proceeding, including PG&E's resulting governance structure, comply with the requirements of Public Utilities Code Section 3292(b)(1).

2. PG&E's executive compensation plan, as modified by ACR Proposal 9, conditionally satisfies the requirements of Public Utilities Code Section 8389(e)(6)(C).

3. Investigation 15-08-019 should remain open.

4. As to other Commission investigations and proceedings, including but not limited to potential investigations involving the Kincade Fire, the plan should make clear that "neither confirmation nor consummation of the plan shall affect any pending or future Commission proceeding or investigation, including any

adjudication or disposition thereof, and any liability of the Debtors or Reorganized Debtors, as applicable, arising therefrom shall not be discharged, waived, or released.”

5. Regional restructuring of PG&E should be initiated.

6. An Enhanced Oversight and Enforcement process for PG&E should be adopted.

7. PG&E should be granted authorization to issue long-term and short-term debt consistent with its plan of reorganization.

8. PG&E should reimburse the Commission for the fees and expenses incurred by the Commission for its outside counsel and financial advisor for services rendered relating to the Chapter 11 cases, related proceedings and associated financings, and PG&E should not seek cost recovery of the Commission’s costs for such fees and expenses.

9. Neither this decision nor PG&E’s reorganization plan and other documents resolving the insolvency proceeding limit or otherwise modify the Commission’s authority or jurisdiction.

## **O R D E R**

**IT IS ORDERED** that:

1. Pacific Gas and Electric Company’s (PG&E’s) reorganization plan and other documents resolving the insolvency proceeding, including PG&E’s resulting governance structure, are approved consistent with the terms and conditions of this decision.

2. Pacific Gas and Electric Company is directed to ensure that its plan makes clear that “neither confirmation nor consummation of the plan shall affect any pending or future Commission proceeding or investigation, including any

adjudication or disposition thereof, and any liability of the Debtors or Reorganized Debtors, as applicable, arising therefrom shall not be discharged, waived, or released.”

3. Pacific Gas and Electric Company is ordered to implement regional restructuring consistent with this decision.

4. An Enhanced Oversight and Enforcement process for Pacific Gas and Electric Company is adopted consistent with this decision.

5. Pacific Gas and Electric Company is authorized to issue long-term and short-term debt consistent with its plan of reorganization.

6. Pacific Gas and Electric Company shall submit a Tier 2 Advice Letter to the Commission's Energy Division within 30 days of the Effective Date of its Plan to implement the debt cost savings associated with the \$11.85 billion Noteholder Restructuring Support Agreement debt.

7. Pacific Gas and Electric Company (PG&E) shall reimburse the Commission for payment of the fees and expenses incurred by the Commission for its outside counsel and financial advisor for services rendered relating to the Chapter 11 cases, related proceedings and associated financings. PG&E may not seek cost recovery of the Commission’s costs for such fees and expenses.

8. Pacific Gas and Electric Company shall submit a Tier 3 Advice Letter to the Commission's Energy Division no later than one year before the expiration of the term of the federal court monitor, with a proposed scope of work, budget, solicitation process for an Independent Safety Monitor, and a process for selection/approval by the Commission. Energy Division will process the Tier 3 Advice Letter in consultation with the Commission’s Safety Enforcement Division and Safety Policy Division, as appropriate.

9. Pacific Gas and Electric Company shall annually submit to the Commission's Energy Division a Tier 1 Advice Letter, until further direction, informing the Commission of its current capital structure and deviation from its authorized capital structure, an updated annual forecast for de-leveraging, and its current credit ratings for secured and unsecured debt.

10. This proceeding remains open.

This order is effective today.

Dated May 28, 2020, at San Francisco, California.

MARYBEL BATJER

President

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

GENEVIEVE SHIROMA

Commissioners

**APPENDIX A**

**ENHANCED OVERSIGHT AND  
ENFORCEMENT PROCESS**

## **Appendix A**

### **Enhanced Oversight and Enforcement Process**

The Commission adopts an Enhanced Oversight and Enforcement Process (Process) designed to provide a clear roadmap for how the Commission will closely monitor PG&E's performance in delivering safe, reliable, affordable, clean energy.

The Process contains six steps which are triggered by specific events, some of which would rely on Safety and Operational Metrics. The Process includes enhanced reporting requirements and additional monitoring and oversight. The Process also contains provisions for PG&E to cure and permanently exit the Process if it can satisfy specific criteria. If PG&E is placed into the Process, actions taken would occur in coordination with the Commission's existing formal and informal reporting requirements and procedures. The Process does not replace or limit the Commission's regulatory authority, including the authority to issue Orders to Show Cause and Orders Instituting Investigations and to impose fines and penalties.

Except as otherwise provided below, a Commission Resolution would place PG&E in the appropriate step based upon the occurrence of a specified triggering event. PG&E shall report the occurrence of a triggering event to the Commission's Executive Director no later than five business day after the date on which any member of senior management of PG&E becomes aware of the occurrence of a triggering event.<sup>25</sup> PG&E should presumptively move through the steps of the Process sequentially but the Commission may place PG&E in the appropriate step upon the occurrence of a specified triggering event.

#### **1. Enhanced Reporting**

##### **STEP 1: Enhanced Reporting**

###### **A. Triggering Events**

- i. PG&E fails to obtain an approved wildfire mitigation plan or fails in any material respect to comply with its regulatory reporting requirements;
- ii. PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics (i) set forth in its approved wildfire mitigation plan including Public Safety Power Shutoffs (PSPS) protocols, (ii) resulting from its on-going safety culture assessment, (iii) contained within the approved Safety and Operational Metrics, or (iv) related to other specified safety

---

<sup>25</sup> Applicable to triggering events that are not based upon a Commission determination.

performance goals;

- iii. PG&E demonstrates insufficient progress toward approved safety or risk-driven investments related to the electric and gas business; or
- iv. PG&E (or PG&E Corporation) fails in any material respect to comply with the Commission's requirements and conditions for approval of its emergence from bankruptcy.

B. Actions During Step 1

PG&E will submit a Corrective Action Plan to the Executive Director within twenty days of a Commission Order placing PG&E into Step 1.

- i. The Corrective Action Plan shall be designed to correct or prevent a recurrence of the Step 1 triggering event, or otherwise mitigate an ongoing safety risk or impact, as soon as practicable and include an attestation stating that it has been approved by the Chief Risk Officer (CRO).
- ii. The Corrective Action Plan, including any timeframes set forth therein for the correction of the triggering events or mitigation of any ongoing safety risk or impact, shall be approved by the Commission or the Executive Director.
- iii. Commission staff will monitor PG&E's compliance with its Corrective Action Plan based on, among other things, existing or enhanced reporting.
- iv. The CRO, the Safety and Nuclear Oversight (SNO) Subcommittee, and the boards of directors shall provide reporting to the Commission as directed.

C. Performance that Results in Exit from Step 1

- i. PG&E shall exit from Step 1 of the Process upon issuance of a Commission Resolution finding that PG&E has met the conditions of its Corrective Action Plan within the required timeframe.
- ii. The Commission, by Resolution, will move PG&E to Step 2 if it fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe. PG&E may remain in Step 1 if it demonstrates sufficient progress toward meeting the conditions of its Corrective Action Plan and additional time appears needed to successfully address the triggering event(s).

## **Step 2: Commission Oversight of Management and Operations**

### **A. Triggering Events**

- i. PG&E fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe as provided in Step 1, Section C (ii) above;
- ii. A gas or electric incident occurs that results in the destruction of 1,000 or more dwellings or commercial structures and appears to have resulted from PG&E's failure to follow Commission rules or orders or prudent management practices;
- iii. PG&E fails to comply with electric reliability performance metrics, including standards to be developed for intentional de-energization events (i.e., PSPS) and any that may be contained within the approved Safety and Operational Metrics; or
- iv. PG&E fails to report to the Commission a systemic electric or gas safety issue.

### **B. Actions During Step 2**

- i. PG&E will submit a Corrective Action Plan, or updated Corrective Action Plan, to the Executive Director within twenty days of a Commission Order placing PG&E into Step 2.
- ii. The Corrective Action Plan shall be designed to correct or prevent a recurrence of the Step 2 triggering event, or otherwise mitigate an ongoing safety risk or impact, as soon as practicable and shall include an attestation stating that it has been approved by the CRO and the SNO Subcommittee.
- iii. The Corrective Action Plan, including any timeframes set forth therein for the correction or prevention of the Step 2 triggering events or mitigation of any ongoing safety risk or impact, shall be approved by the Commission or the Executive Director.
- iv. Commission staff will monitor PG&E's compliance with its Corrective Action Plan based on, among other activities, increased inspections, quarterly reports, and, to the extent applicable, spot auditing of General Rate Case, Wildfire Expense Memorandum Account, Catastrophic Events Memorandum Account, or Pipeline Safety Enhancement Plans accounts in which approved investments in wildfire mitigation, electric or gas safety are auditable.
- v. A representative of the SNO Subcommittee and the CRO shall appear quarterly before the Commission to report progress on the Corrective Action Plan and provide additional reporting as directed.

C. Performance that Results in Exit from Step 2

- i. PG&E shall exit from Step 2 upon issuance of a Commission Resolution finding that the company has met the conditions of its Step 2 Corrective Action Plan within the required timeframe. The Commission may move PG&E back to Step 1 of the Process rather than exit the process if it determines that PG&E has made sufficient progress in meeting its Step 2 Corrective Action Plan but continued enhanced reporting is needed.
- ii. The Commission, by Resolution, will move PG&E to Step 3 if PG&E fails to adequately meet the conditions of its Corrective Action Plan and additional time in Step 2 is not likely to result in the effective implementation of its Corrective Action Plan.

**2. Enhanced Enforcement**

Steps 3 through 6 of the Process implement increasing levels of operational oversight upon occurrence of certain triggering events.

**Step 3: Appointment of Independent Third-Party Monitor**

A. Triggering Events

- i. PG&E fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe, as provided in Step 2, Section C (ii); or
- ii. PG&E fails to obtain or maintain its safety certificate as provided in AB 1054.

B. Actions During Step 3

- i. The Commission's Executive Director may appoint an independent third- party monitor (Monitor), or expand the authority of any Independent Safety Monitor previously appointed by the Commission, to oversee PG&E's operations and to work with senior management to develop and implement a Corrective Action Plan with reasonable timeframes to address the triggering event(s) as soon as practicable.
- ii. The Monitor will provide active, external oversight of PG&E's implementation of its Corrective Action Plan.
- iii. The Monitor will have the authority to hire third-party safety and utility operations experts to assist it with its oversight obligations.
- iv. PG&E's senior management must work jointly with the Monitor to develop and implement a Corrective Action Plan including reasonable timeframes (which timeframes shall be acceptable to the Commission). The Corrective Action Plan shall be certified by the Monitor.

- v. PG&E may request the Monitor to modify the Corrective Action Plan but must otherwise implement the plan as approved by the Monitor.
- vi. The Monitor will provide quarterly reports to the Commission and to PG&E's board of directors on the progress towards implementing the Corrective Action Plan.
- vii. The CRO and SNO Subcommittee will provide reporting to the Commission as required during this Step.

C. Performance that Results in Exit from Step 3

- i. PG&E shall exit from Step 3 upon issuance of a Commission Resolution finding that PG&E has met the conditions of its Step 3 Corrective Action Plan within the required timeframe. The Commission may determine that PG&E must remain in Step 1 or 2 for additional time after it confirms that PG&E has exited Step 3.
- ii. The Commission, by Resolution, will move PG&E to Step 4 if any of the following occurs:
  - a. PG&E fails to implement the Corrective Action Plan within the timeframes required by the Monitor or the Commission's Executive Director.
  - b. The Commission determines that additional enforcement is necessary because of PG&E's systemic non-compliance or poor performance with its Safety and Operational Metrics over an extended period.

**Step 4: Appointment of a Chief Restructuring Officer**

A. Triggering Events

- i. PG&E fails to adequately meet the conditions of its Corrective Action Plan within the required timeframe and additional time in Step 3 is not likely to result in the effective implementation of its Corrective Action Plan, as provided in Step 3, Section C (ii)(a);
- ii. Additional enforcement is necessary because of PG&E's systemic non-compliance or poor performance with its Safety and Operational Metrics over an extended period;
- iii. The Commission determines through an Order to Show Cause, Order Instituting Investigation, or other appropriate process, that PG&E repeatedly violated its regulatory requirements, committed gross negligence, or committed a serious violation of the law, such that such conduct in the aggregate represents a threat to public health and safety;
- iv. PG&E causes an electric or gas safety incident that results in the

destruction of 1,000 or more dwellings or commercial structures and the Commission determines through an Order to Show Cause, Order Instituting Investigation, or other appropriate process, that such event results from the willful misconduct or repeated and serious violations of Commission rules, orders or regulatory requirements;

- v. The Commission determines through an Order to Show Cause, Order Instituting Investigation, or other appropriate process that additional enforcement is necessary because the wildfire fund administrator has made a determination following a covered wildfire that PG&E is ineligible for the cap on reimbursement because its actions or inactions that resulted in a covered wildfire constituted conscious or willful disregard of the rights and safety of others; or
- vi. PG&E failed to obtain or maintain its safety certificate as provided in AB 1054 for a period of three consecutive years.

B. Actions During Step 4

- i. The Commission will require that PG&E retain a chief restructuring officer from a list of qualified candidates identified by a third-party. The chief restructuring officer will have full management responsibility for developing and directing PG&E to implement the Corrective Action Plan with reasonable timeframes to address the triggering event(s) as soon as practicable.
- ii. The chief restructuring officer will have the authority of an executive officer of PG&E and will report to the SNO Committee on all safety issues.
- iii. PG&E's senior management must work jointly with the chief restructuring officer to develop and implement a Corrective Action Plan including reasonable timeframes (which timeframes shall be acceptable to the Commission).
- iv. The chief restructuring officer will have all corporate authority that can be delegated to an officer under the California Corporations Code in order to ensure that PG&E can meet its Corrective Action Plan.
- v. The Corrective Action Plan must be certified by the chief restructuring officer.
- vi. PG&E must otherwise implement the Corrective Action Plan as certified by the chief restructuring officer.
- vii. The chief restructuring officer will provide quarterly reports to the Commission and to PG&E's board of directors on the progress towards implementing the Corrective Action Plan.

- viii. The Chief Restructuring Officer will remain in place during Steps 5 and 6, if triggered.

C. Performance that Results in Exit from Step 4

- i. PG&E shall exit from Step 4 upon issuance of a Commission Resolution finding that it met the conditions of its Step 4 Corrective Action Plan within the required timeframe. The Commission may determine that PG&E must remain in Steps 1, 2, or 3 for additional time after PG&E has exited Step 4.
- ii. The Commission by Resolution will move PG&E to Step 5 if the Commission finds that PG&E failed to implement the Corrective Action Plan within the timeframes required by the chief restructuring officer or the Commission.
- iii. PG&E may remain in Step 4 if the Commission determines that additional time appears needed to successfully address the triggering event(s).

**Step 5: Appointment of a Receiver**

A. Triggering Events

- i. PG&E fails to implement its Step 4 Corrective Action Plan within the required timeframes, as provided in Step 4, Section C (ii).

B. Process

- i. The Commission will pursue the receivership remedy subject to then applicable law of the state of California. If PG&E becomes the subject of a subsequent chapter 11 case, PG&E will agree not to dispute the Commission's or state of California's authority to file a motion for the appointment of a chapter 11 trustee.
- ii. The receiver, if appointed by the Superior Court, would be empowered to control and operate PG&E's business units in the public interest but not dispose of the operations, assets, business or PG&E stock.

C. Performance that Results in Exit from Step 5

- i. If the Commission by Resolution determines that PG&E has corrected all of the Step 5 triggering events and has remained in material compliance with Safety and Operational Metrics for a period of 18 months, the Commission may request termination of any receivership.
- ii. At any time while the receiver is in place and to the extent permitted by then applicable law, the Commission can initiate a Step 6 enforcement action if a Step 6 triggering event has occurred.

- iii. In the event that the Commission seeks, but is not successful in obtaining a receiver, or if the Step 5 triggering event occurs and California law does not allow for the appointment of a receiver, the Commission would determine whether PG&E shall remain in Step 4 or advance to Step 6.

## **Step 6: Review of CPCN**

### **A. Triggering Events**

- i. A receiver appointed as set forth above has determined that continuation of Receiver Oversight will not result in restoration of safe and reliable service; provided that such receiver shall have been in place for a period of at least nine (9) months before making such a determination;
- ii. A court of applicable jurisdiction has denied the Commission's request for a receiver made as set forth above or the Step 5 triggering event has occurred and California law does not provide for the appointment of a receiver; or
- iii. PG&E fails adequately to address the Step 5 triggering event within 18 months of imposition of Step 5 and the Commission determines that additional time in Step 5 is unlikely to result in corrective action.

### **B. Process**

- i. The Commission will undertake this process subject to then applicable law of the state of California.
- ii. The CPUC will issue an Order to Show Cause or Order Instituting Investigation to initiate Step 6
- iii. As a result of the Order to Show Cause, the CPUC may place conditions on PG&E's CPCN or revoke PG&E's CPCN.

**(END OF APPENDIX A)**

# Addendum 4

ALJ/PD1/jt2

**Date of Issuance 10/24/2019**

Decision 19-10-056 October 24, 2019

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to  
Consider Authorization of a  
Non-Bypassable Charge to Support  
California's Wildfire Fund.

Rulemaking 19-07-017

**DECISION APPROVING IMPOSITION OF A NON-BYPASSABLE CHARGE TO  
SUPPORT CALIFORNIA'S WILDFIRE FUND AND ADOPTING RATE  
AGREEMENT BETWEEN THE CALIFORNIA DEPARTMENT OF WATER  
RESOURCES AND THE CALIFORNIA PUBLIC UTILITIES COMMISSION**

## Table of Contents

| Title                                                                                                                                                                                                                                | Page |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------|
| DECISION APPROVING IMPOSITION OF A NON-BYPASSABLE CHARGE TO SUPPORT CALIFORNIA’S WILDFIRE FUND AND ADOPTING RATE AGREEMENT BETWEEN THE CALIFORNIA DEPARTMENT OF WATER RESOURCES AND THE CALIFORNIA PUBLIC UTILITIES COMMISSISON..... | 1    |
| Summary .....                                                                                                                                                                                                                        | 2    |
| 1. Background.....                                                                                                                                                                                                                   | 2    |
| 2. Jurisdiction.....                                                                                                                                                                                                                 | 5    |
| 3. Issues Before the Commission .....                                                                                                                                                                                                | 6    |
| 4. The Annual Revenue Requirement for the Wildfire Fund NBC .....                                                                                                                                                                    | 8    |
| 4.1. Impact of Collections from Regional Electrical Corporation Ratepayers.....                                                                                                                                                      | 8    |
| 4.2. The Revenue Requirement for Large Electrical Corporation Ratepayers is Based on Average Annual Collections Not Authorizations.....                                                                                              | 10   |
| 4.2.1. The Revenue Requirement is Based on participating Large Electrical Corporations .....                                                                                                                                         | 15   |
| 4.2.2. Approved Revenue Requirement .....                                                                                                                                                                                            | 19   |
| 4.2.3. Impact of Large Electrical Corporation Participation on the Amount of Bonds Issued .....                                                                                                                                      | 20   |
| 5. The Commission’s Rate Agreement with the Department of Water Resources .....                                                                                                                                                      | 21   |
| 6. Wildfire Fund NBC Rate Design .....                                                                                                                                                                                               | 24   |
| 6.1. Wildfire Fund NBC Revenue Allocation.....                                                                                                                                                                                       | 25   |
| 6.2. Exclusions of Certain Customers from the Wildfire Fund NBC.....                                                                                                                                                                 | 27   |
| 6.2.1. Exclusion for CARE and Medical Bseline Residential Customers.....                                                                                                                                                             | 27   |
| 6.2.2. Exclusion for Continuous DA Customers .....                                                                                                                                                                                   | 27   |
| 6.2.3. Net Energy Metering Customers .....                                                                                                                                                                                           | 29   |
| 6.2.4. Exclusions for Customers of Regional Electrical Corporations.....                                                                                                                                                             | 30   |
| 6.3. Establishing an Annual Wildfire Fund NBC Rate Design Process.....                                                                                                                                                               | 31   |
| 7. It is Just and Reasonable to Impose the Wildfire Fund NBC .....                                                                                                                                                                   | 32   |
| 7.1. Public Policy Findings of the Legislature .....                                                                                                                                                                                 | 33   |
| 7.2. The Wildfire Insurance Fund Insulates Ratepayers from Liability Attached to Wildfires Caused by a Utility .....                                                                                                                 | 34   |
| 7.3. Financial Stability of Electrical Corporations and Reduced Financing Costs .....                                                                                                                                                | 36   |

## Table of Contents (cont.)

| Title                                                              | Page                                |
|--------------------------------------------------------------------|-------------------------------------|
| 7.4. Counterarguments .....                                        | <b>Error! Bookmark not defined.</b> |
| 7.4.1. Due Process .....                                           | 39                                  |
| 7.4.2. Ratepayer Reimbursements of Wildfire Fund Withdrawals ..... | 43                                  |
| 7.4.3. Alleged Disincentives for Safe Utility Operation .....      | 48                                  |
| 7.4.4. Bill Impacts of theWildfire Fund NBC .....                  | 51                                  |
| 7.4.5. Controls on Administrative Costs and Expenses .....         | 52                                  |
| 8. Comments on Proposed Decision .....                             | 54                                  |
| 9. Assignment of Proceeding .....                                  | 55                                  |
| Findings of Fact.....                                              | 55                                  |
| Conclusions of Law .....                                           | 56                                  |
| ORDER .....                                                        | 61                                  |

Attachment A – Rate Agreement

Attachment B – Relevant California Public Utilities Code (PUC) Sections

**DECISION APPROVING IMPOSITION OF A NON-BYPASSABLE CHARGE TO  
SUPPORT CALIFORNIA'S WILDFIRE FUND AND ADOPTING RATE  
AGREEMENT BETWEEN THE CALIFORNIA DEPARTMENT OF WATER  
RESOURCES AND THE CALIFORNIA PUBLIC UTILITIES COMMISSION**

**Summary**

This decision finds that it is appropriate for the Commission to exercise its broad authority to impose a non-bypassable charge on the ratepayers of California's large electrical corporations in order to support California's new Wildfire Fund, and that the imposition of such a charge is just and reasonable. This decision finds that the imposition of the non-bypassable charge is in the public interest, supports the financial stability of the large electrical corporations, reduces the costs to ratepayers associated with catastrophic wildfires caused by utility equipment, and allows the large electrical corporations to attract lower-cost capital to carry out necessary improvements, including the mitigation of wildfire threats posed by utility infrastructure.

This decision also implements the statutory directives regarding the revenue requirement and rate design that shall be used for setting and implementing the non-bypassable charge, adopts a Rate Agreement between the Commission and the Department of Water Resources, giving Section 5.1 of that agreement the force and effect of a financing order, and determines that ratepayers of any non-participating electrical corporations shall not pay the non-bypassable charge.

**1. Background**

Assembly Bill 1054 (Ch. 79, Stats. 2019) (AB 1054) was enacted as an urgency measure to address the dangers and devastation from catastrophic

wildfires in California caused by electric utility<sup>1</sup> infrastructure, including the increased costs to ratepayers resulting from electric utilities' exposure to financial liability. AB 1513 (Ch. 396, Stats. 2019) subsequently modified AB 1054 and a companion bill, AB 111 (Ch. 81, Stats. 2019), was also enacted. At the outset of this decision, the Commission acknowledges the devastation caused by these recent fires and the tragic losses suffered by Californians in these catastrophes.

The Governor signed AB 1054 on July 12, 2019. As required by statute, the Commission moved quickly after AB 1054 was enacted into law to open a rulemaking to consider providing ratepayer funding for a fund established by Public Utilities Code Section 3284 (Wildfire Fund) to support the financial stability of California's electrical corporations, one element of the multi-faceted solution posed by the statute. The Commission issued an Order Instituting Rulemaking (OIR) at a meeting on July 26, 2019, consistent with Public Utilities Code Section 3289, in response to legislative direction in AB 1054 to consider whether the Commission should exercise its authority to require certain electrical corporations to collect from ratepayers a non-bypassable charge to support California's new Wildfire Fund defined in Public Utilities Code Sections 1701.8 and 3280 et seq. The OIR contained a preliminary scope and schedule for the proceeding. Notice of the Rulemaking appeared on the Commission's Daily Calendar on July 30, 2019. In the OIR the Commission preliminarily categorized this proceeding as ratesetting and determined hearings were not necessary.

The OIR set a date for a prehearing conference (PHC) of August 8, 2019. PHC statements were filed by Ruth Henricks on August 6, 2019 and by

---

<sup>1</sup> Throughout this decision, the terms "utility" and "electrical corporation" are used interchangeably. For the legislative intent of AB 1054 referred to here, see Stats. 2019, ch. 79, § 1(a).

San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), Wild Tree Foundation, Bear Valley Electric Service, a division of Golden State Water Company (Bear Valley), Liberty Utilities (CalPeco Electric) LLC (Liberty), Utility Consumers' Action Network (UCAN), PacifiCorp d/b/a Pacific Power (PacifiCorp), the Coalition of California Utility Employees (CCUE), The Utility Reform Network (TURN), Energy Producers and Users Coalition (EPUC), Bioenergy Association of California, the California Public Advocates Office at the California Public Utilities Commission (Cal Advocates), and Pacific Gas and Electric Company (PG&E) on August 7, 2019. The PHC was held on August 8, 2019 to discuss the issues of law and fact, the need for hearing, and the proceeding schedule for resolving the matter.

The respondents to the OIR – SCE, SDG&E, Bear Valley, Liberty, PacifiCorp, and PG&E – were automatically made parties to the proceeding. At the PHC, party status was also granted to the following entities: Institutional Equity Investors, California Large Energy Consumers Association (CLECA), EPUC, California Manufacturers and Technology Association (CMTA), Trans Bay Cable, LLC, Horizon West Transmission, LLC, California Farm Bureau Federation (CFBF), Western States Petroleum Association (WSPA), Solar Energy Industries Association (SEIA), William Abrams, CCUE, California Choice Energy Authority, Pioneer Community Energy, Silicon Valley Clean Energy Authority, Redwood Coast Energy Authority, Monterey Bay Community Power Authority, Sonoma Clean Power Authority, Marin Clean Energy, Peninsula Clean Energy Authority, Wild Tree Foundation, UCAN, Ruth Henricks, the Center for Accessible Technology (CforAT), Cal Advocates, and TURN.

The assigned Commissioner's scoping memo and ruling (scoping memo) in this proceeding was filed on August 14, 2019. An Administrative Law Judge's

(ALJ) ruling soliciting party comment on a proposed Rate Agreement between the Commission and the Department of Water Resources was filed on August 21, 2019. An ALJ ruling soliciting party comment on the revenue requirement calculation to be used in this proceeding was filed on August 23, 2019.

Comments on the issues scoped into this proceeding were filed and served by SCE, SDG&E, Bear Valley, Liberty, PacifiCorp, PG&E, CLECA, EPUC, CCUE, Wild Tree Foundation, UCAN, Ruth Henricks, CforAT, Cal Advocates, TURN, and Pioneer Community Energy, California Choice Energy Authority, Sonoma Clean Power Authority, Peninsula Clean Energy Authority, Silicon Valley Clean Energy Authority, Marin Clean Energy, Monterey Bay Community Power Authority, and Redwood Coast Energy Authority<sup>2</sup> jointly as Joint CCAs, on August 29, 2019. Reply comments were filed and served by Wild Tree Foundation on September 5, 2019 and by SEIA, UCAN, Bear Valley, CforAT, Joint CCAs, WSPA, PG&E, SDG&E, SCE, PacifiCorp, CLECA, EPUC, Cal Advocates, TURN, CCUE, and Ruth Henricks on September 6, 2019. The record of the proceeding was considered submitted on September 6, 2019.

A motion for oral argument was filed by Ruth Henricks on September 6, 2019. The motion was granted, and oral argument in this proceeding was held on October 10, 2019.

## **2. Jurisdiction**

AB 1054 directs the Commission to consider whether to impose the Wildfire Fund non-bypassable charge (Wildfire Fund NBC) under its authority

---

<sup>2</sup> Hereinafter referred to collectively as Joint CCAs.

as defined by Public Utilities Code Section 701.<sup>3</sup> Various parties supported an interpretation of Public Utilities Code Section 701 that grants the Commission authority to impose the Wildfire Fund NBC on ratepayers of electrical corporations participating in the Wildfire Fund.<sup>4</sup> The Commission agrees that the broad powers granted to it by Public Utilities Code Section 701, and the Legislature's endorsement of the Commission's authority under that statute to impose the Wildfire Fund NBC, grant the Commission jurisdiction and authority to impose the Wildfire Fund NBC.

By referring to Public Utilities Code Section 701, Public Utilities Code Section 3289(a)(1) directs the Commission to apply its broadest discretion and authority when determining if it is in the public interest and just and reasonable to impose the Wildfire Fund NBC.<sup>5</sup>

### **3. Issues Before the Commission**

It is important to note that while the Wildfire Fund is part of the Legislature's broader response to the threat of catastrophic wildfires set out in AB 1054, the scope of this proceeding is limited to whether the Commission should exercise its broad ratemaking authority to determine if it is just and reasonable to impose the Wildfire Fund NBC, as well as directly related issues necessary to implement the Wildfire Fund NBC such as the revenue requirement to be authorized and the Rate Agreement to be entered into between the

---

<sup>3</sup> Pub. Util. Code § 3289(a)(1).

<sup>4</sup> PG&E opening comments at 2; SCE opening comments at 2; SDG&E opening comments at 2; EPUC opening comments at 4 (concluding that Pub. Util. Code § 701 gives the Commission discretion not to impose the Wildfire Fund NBC at all).

<sup>5</sup> See *Southern Cal. Edison v. Peevey* (2003) 31 Cal.4th 781, 792.

Commission and the Department of Water Resources. The scoping memo sets out the following issues for consideration in this proceeding:

- Whether it is appropriate for the Commission to exercise its statutory authority, including under Public Utilities Code Section 701, to require certain electrical corporations to impose a non-bypassable charge on ratepayers to support California's Wildfire Fund established by AB 1054, including payment of bonds issued pursuant to Section 80500 et seq. of the Water Code.
- Whether imposition of the Wildfire Fund NBC is just and reasonable.
- The amount of the revenue requirement referred to in Section 3289 of the Public Utilities Code, including calculation of the amount and accounting for any impact of collections from regional electrical corporation ratepayers.
- Whether to approve the Commission's Rate Agreement with the Department of Water Resources pursuant to Water Code Section 80524(b).
- Whether it is reasonable to impose the Wildfire Fund NBC on PG&E customers if PG&E is deemed ineligible to participate in the Wildfire Fund.
- The Commission's process for determining and collecting the Wildfire Fund NBC "in the same manner as" payments made historically under the Department of Water Resources (DWR) bond charge as specified in Public Utilities Code Section 3289(a)(2).
- Other issues relating to the Wildfire Fund NBC that must be addressed before the Wildfire Fund NBC may be imposed.

AB 1054 contains several provisions designed to facilitate the safe operation of utility infrastructure and reduce the risk of utility-caused wildfire. Some parties sought to include in the scope of this proceeding issues related to

these safety-specific provisions of AB 1054.<sup>6</sup> Other parties sought to litigate provisions of AB 1054 related to the utility's burden of proof when seeking recovery for eligible wildfire claims, arguing that these provisions created less financial incentives for the safe operation of utility infrastructure.<sup>7</sup>

While some parties have concerns about the new statutory provisions embodied in AB 1054, the text of the statute is not subject to revision by the Commission in this proceeding.

#### **4. The Annual Revenue Requirement for the Wildfire Fund NBC**

One of the tasks before the Commission in this proceeding is to determine the amount of the revenue requirement identified by Section 3289 of the Public Utilities Code, accounting for any impact of collections from regional electrical corporation ratepayers.

##### **4.1. Impact of Collections from Regional Electrical Corporation Ratepayers**

Public Utilities Code Section 3289(a)(1)(A) requires the Commission to consider imposing the Wildfire Fund NBC for large electrical corporation customers "in an amount sufficient to fund the revenue requirement, as established pursuant to Section 80524 of the Water Code." For customers of regional electrical corporations the law establishes a Wildfire Fund NBC of \$0.005/kilowatt-hour (kWh).<sup>8</sup> This charge is collected in rates, but the statute

---

<sup>6</sup> Reporter's Transcript (RT) 25:21-27 (comments of Wild Tree Foundation at the PHC concerning the safety certification process); RT 26:20-25 (comments of Abrams concerning the changes to the schedule for consideration of wildfire mitigation plans).

<sup>7</sup> See, e.g., Henricks PHC statement at 10; Wild Tree Foundation PHC statement at 3.

<sup>8</sup> Pub. Util. Code § 3289(a)(1)(B).

provides that it is not remitted to DWR, and is instead directly deposited into the Wildfire Fund.<sup>9</sup> Further, Section 3289(a)(1)(A)'s reference to the revenue requirement is contained in a sentence referring to large electrical corporations rather than electrical corporations generally. The Legislature intended for the revenue requirement established by Water Code Section 80524 to only apply to customers of large electrical corporations, while customers of regional electrical corporations would not be subject to a specific revenue requirement and would simply pay the statutorily determined rate for the Wildfire Fund NBC if their serving utility voluntarily established a charge.

In its opening comments, PG&E offers a different interpretation whereby "the shares of the revenue requirement allocated to the large electrical corporations may need to be adjusted to take into account the amount of contributions provided by the regional electrical corporations that choose to participate in the Wildfire Fund."<sup>10</sup> Similar statements were made by other parties. For example, Bear Valley argued that it is appropriate for the contributions of regional electrical corporation ratepayers to be included in the "overall" calculation of the revenue requirement.<sup>11</sup>

This decision follows the statutory language, which provides that collections from the ratepayers of regional electrical corporations shall be remitted directly to the Wildfire Fund administrator, and will not be remitted to DWR.<sup>12</sup> Those collections will not adjust the annual revenue requirement for the Wildfire Fund NBC established in Water Code Section 80524(a) or be covered by

---

<sup>9</sup> Pub. Util. Code § 3292(b)(2).

<sup>10</sup> PG&E opening comments at 4.

<sup>11</sup> Bear Valley opening comments at 5.

<sup>12</sup> Pub. Util. Code § 3292(b)(2).

the Rate Agreement between DWR and the Commission. Any collections from regional electrical corporation ratepayers shall be regarded as additional to the revenue requirement established by this decision.

The Commission notes that this issue may be moot as the regional electrical corporations have notified the Commission that they do not intend to participate in the Wildfire Fund.<sup>13</sup> However, to the extent any regional electrical corporation elects to participate in the Wildfire Fund, this decision must take the step of establishing what the Wildfire Fund NBC will be for the regional electrical corporation. Pursuant to Public Utilities Code Section 3289, for any regional electrical corporation that voluntarily imposes a Wildfire Fund NBC on its customers, that Wildfire Fund NBC shall be one-half cent per kWh.

#### **4.2. The Revenue Requirement for Large Electrical Corporation Ratepayers is Based on Average Annual Collections**

Public Utilities Code Section 3289(a)(1)(A) refers to “the revenue requirement” for large electrical corporations, referring to Water Code Section 80524 for more detail. Section 80524 of the Water Code is, like Public Utilities Code Section 3289, a creation of AB 1054. With respect to the revenue requirement for the Wildfire Fund NBC, Water Code Section 80524(a) states:

The revenue requirement for each year or, with respect to the first year and last year, the pro rata portion of the year, shall be equal to the average annual amount of collections by the [Department of Water Resources] with respect to charges imposed pursuant to the revenue requirements established by the [Department of Water Resources] under Section 80110 of Division 27 [of the Water Code]

---

<sup>13</sup> PacifiCorp Notice of Intent, served August 28, 2019; Liberty Notice of Intent, served September 10, 2019; Bear Valley Notice of Election not to Participate in Wildfire Fund, served September 11, 2019.

for the period from January 1, 2013, through December 31, 2018. The revenue requirement shall remain in effect until January 1, 2036.

This decision therefore holds that the plain meaning of the statute is to base the revenue requirement calculation on the actual collections made by DWR historically for the DWR Bond Charge, not the revenue requirement authorized historically for the DWR Bond Charge, or the per kilowatt-hour (kWh) charge levied for the DWR Bond Charge, as recommended by parties such as CLECA and TURN.<sup>14</sup>

The Commission's Energy Division compiled a table showing the DWR Bond Charge collections received by DWR in the years 2013, 2014, 2015, 2016, 2017, and 2018, using data supplied by the Department of Water Resources in proceeding Rulemaking (R.) 15-02-012. The Commission's Energy Division verified the amounts by comparing the sums to the total annual collections reported by DWR in annual reports made available through the Electronic Municipal Market Access website.<sup>15</sup> The table, which was supplied to parties for comment in an ALJ ruling of August 23, 2019, appears below.

---

<sup>14</sup> See, e.g., TURN opening comments at 6-8 (arguing for the use of the annual authorized revenue requirement rather than collections and claiming that "[t]he average kWh nonbypassable charge over the 2013-2018 period is the foundational value which the Commission should use as a cap for the Wildfire Fund bond charge and its associated revenue requirement"); CLECA reply comments at 4 (seeking a cap of \$880 million per year based on historic DWR Bond Charge authorizations); PG&E opening comments at 4 (recommending the Commission interpret the word "collections" to include a true-up mechanism to ensure the Wildfire Fund NBC does not collect more than necessary to service DWR's eventual bond issuance).

<sup>15</sup> These reports are public and available for 2013-2015 at <https://emma.msrb.org/ES1040110.pdf>, p. 21; for 2016 at <https://emma.msrb.org/ES1200377.pdf>, p.35; for 2017 at <https://emma.msrb.org/ES1274739.pdf>, p.35; and for 2018 at <https://emma.msrb.org/ES1386549.pdf>, p.38.

**Annual Collections Received by DWR for the DWR Bond Charge (Millions)**

| <b>Year</b>            | <b>PG&amp;E</b> | <b>SCE</b> | <b>SDG&amp;E</b> | <b>Total</b> |
|------------------------|-----------------|------------|------------------|--------------|
| 2013                   | \$383.8         | \$381.8    | \$84.5           | \$850.1      |
| 2014                   | \$406.6         | \$402.6    | \$89.8           | \$898.9      |
| 2015                   | \$409.2         | \$408.8    | \$90.8           | \$908.8      |
| 2016                   | \$408.6         | \$412.9    | \$90.0           | \$911.5      |
| 2017                   | \$410.8         | \$421.9    | \$91.4           | \$924.1      |
| 2018                   | \$408.6         | \$421.4    | \$91.1           | \$921.1      |
| Average<br>(2013-2018) | \$404.6         | \$408.2    | \$89.6           | \$902.4      |

Several parties commented on the estimated annual revenue requirement per large electrical corporation in response to the ALJ ruling of August 23, 2019. The large electrical corporations agreed with the figures provided by the Energy Division,<sup>16</sup> or did not object to the figures.<sup>17</sup>

TURN asserted that the reported collections are not net of refunds for overcollections of the DWR Bond Charge made to ratepayers through the DWR Power Charge.<sup>18</sup> TURN claims that in 2015 the DWR Power Charge refunded approximately \$6 million to ratepayers in overcollections relative to the DWR Bond Charge revenue requirement, and that this amount is not reflected in the

---

<sup>16</sup> SCE opening comments at 4; SDG&E opening comments at 12 (confirming the accuracy of the revenue requirement calculation for SDG&E).

<sup>17</sup> PG&E opening comments at 3 (“PG&E has performed a preliminary review of Energy Division’s calculation and has identified no revision or correction to the total number in Row RR of Table 1 at this time”).

<sup>18</sup> TURN opening comments at 3 (“[t]he collected DWR Bond Charge revenue requirement does not account for ‘Excess Amounts’ credited to ratepayers through the DWR Power Charge and accordingly, overstates the amount of the DWR Bond Charge revenue requirement funded by ratepayers”).

revenue requirement data collections prepared by Energy Division. TURN speculates that other years between 2013-2018 could have included such refunds through the DWR Power Charge; but that those amounts are unknown to TURN at this time.<sup>19</sup>

TURN's argument misreads the Commission's decisions which approved the annual DWR Bond Charge and DWR Power Charge as separate and distinct revenue streams to fund separate annual revenue requirements. In Decision (D.) 02-02-051, the Commission determined that establishing separate DWR Bond Charges and DWR Power Charges was in the public interest, delineated the separate uses for each charge, and approved a rate agreement with DWR that segregated DWR Bond Charges from DWR Power Charges.<sup>20</sup> TURN's speculation that DWR Bond Charge overcollections may have been refunded through the DWR Power Charge is not sufficiently supported to contravene the Commission decisions segregating the two charges.

For example, TURN asserts that a negative power charge was employed to refund DWR Bond Charge overcollections in D.11-12-005. That decision shows that in October 2011, DWR submitted a revised revenue requirement that decreased the DWR Bond Charge revenue requirement by \$8 million compared to the forecast submitted by DWR in August 2011. The Commission approved a DWR Bond Charge for that year based on the downwardly revised revenue requirement.<sup>21</sup> There is no discussion or other indication of DWR Bond Charge

---

<sup>19</sup> TURN opening comments at 8-11.

<sup>20</sup> D.02-02-051 at 14-21, 28-29.

<sup>21</sup> D.11-12-005 at 10.

refunds. Separately, DWR's revised revenue requirement resulted in DWR returning \$94 million more to customers than it had planned to in its August 2011 filing, but those refunds stemmed from DWR Power Charge-related cost reductions, not DWR Bond Charge overcollections.<sup>22</sup>

Finally, the "negative revenue requirement" that TURN believes was used to refund DWR Bond Charges was actually attributable to reductions in DWR's operating reserves (i.e., the DWR Power Charge costs), and payments to California from settlements of litigation challenges stemming from the energy crisis of 2000-2001. These reductions were not related to DWR Bond Charge-related costs or collections.<sup>23</sup> This conclusion also applies for D.14-12-002 for similar reasons.

TURN's argument has not raised a material dispute regarding the accuracy of the Energy Division's table showing the compilation of historic average annual collections.

In reply comments, UCAN refers to the analysis by Energy Division as an "exceedingly thin reed" on which to rest this decision's findings.<sup>24</sup> UCAN also supported EPUC's arguments that the revenue requirement should be reduced from the amount of collections received.<sup>25</sup>

The Commission rejects these arguments. The compilation of data that the Energy Division's staff developed was provided to parties for their review and comment. No party raised an objection to the figures provided by Energy Division, with the exception of TURN as discussed previously. The figures

---

<sup>22</sup> D.11-12-005 at 7.

<sup>23</sup> D.11-12-005 at 3-4.

<sup>24</sup> UCAN reply comments at 3.

<sup>25</sup> *Id.*

Energy Division compiled showing the collections received by DWR from the DWR Bond Charge are uncontested. Where facts are uncontested, the record is thickened and where, as here, the facts are sufficiently reliable and their reliability unchallenged, there is no dispute requiring resolution.

Finally, parties such as TURN and UCAN argue that the Commission *should* set a revenue requirement that is lower than the average annual collections by DWR for the DWR Bond Charge over the last several years, or make adjustments to account for DWR's other sources of revenue such as interest. However, AB 1054 is clear that the annual revenue requirement must be based on collections made by DWR for the DWR Bond Charge.<sup>26</sup>

#### **4.2.1. The Revenue Requirement is Based on Participating Large Electrical Corporations**

By establishing the revenue requirement and adopting the Wildfire Fund NBC, this decision implements a series of requirements contained in AB 1054, for example in Public Utilities Code Sections 3289 and 3292, and in Water Code Section 80524. The revenue requirement defines the amounts to be collected and remitted to DWR, and Water Code Section 80524(b) provides that the Commission and DWR are to reach an agreement "with respect to the revenue requirement" and the charges described in Public Utilities Code Section 3289, and that this agreement will have the force and effect of a financing order.

The Rate Agreement adopted by this decision is based on these statutory requirements, including statutory language stating the charge is to be calculated by referring to past DWR Bond Charges assessed on individual ratepayers.<sup>27</sup> As a result, the Rate Agreement ensures that the revenue requirement that will be

---

<sup>26</sup> Water Code §§ 80524(a), 80550(b).

<sup>27</sup> Pub. Util. Code § 3289, Water Code § 80524.

funded by the Wildfire Fund NBC is to be collected from individual ratepayers whose serving utility is participating in the fund, which is consistent with the principle that the ratepayers of an electrical corporation that is not participating in the Wildfire Fund should not pay the Wildfire Fund NBC. The Director of DWR submitted a memorandum to the Executive Director of the Commission explaining that the calculation method provided in the Rate Agreement harmonizes the statutory provisions and implements the overall legislative intent for AB 1054.<sup>28</sup> This analysis by the agency with responsibility for implementing the Water Code gives this Commission appropriate guidance for interpreting the statute as a whole.

Having a non-participating electrical corporation's ratepayers not pay the Wildfire Fund NBC was broadly supported by parties in their comments.<sup>29</sup> In fact, no party suggested that a non-participating electrical corporation's ratepayers should be made to pay the Wildfire Fund NBC.<sup>30</sup> The Joint CCAs state the principle as "customers of an [electrical corporation] should not be required to pay the Wildfire Fund NBC if benefits from the Wildfire Fund are not directly available to the [electrical corporation]."<sup>31</sup> CforAT's version of the principle states that an electrical corporation "should not be directed to impose

---

<sup>28</sup> August 21, 2019 ALJ Ruling seeking party comment on proposed Rate Agreement, Attachment 2.

<sup>29</sup> Bear Valley opening comments at 5; CLECA opening comments at 9-10; CforAT opening comments at 6; TURN opening comments at 19-20; UCAN opening comments at 5; Cal Advocates opening comments at 17-18; PG&E opening comments at 5; PacifiCorp opening comments at 3.

<sup>30</sup> SCE's opening comments do suggest that the issue of how to treat PG&E's ratepayers in the event PG&E cannot participate in the Wildfire Fund is not ripe for consideration at this time.

<sup>31</sup> Joint CCAs reply comments at 11-12.

and collect the [Wildfire Fund NBC] if the [electrical corporation] is not participating in the Wildfire Fund.”<sup>32</sup> Further, SDG&E raised a concern, shared by other parties, that its ratepayers would be responsible for substantially more revenue requirement than historically assigned to them in the event PG&E is ineligible to participate in the fund.<sup>33</sup>

As a matter of law, the ratepayers of an electrical corporation that is not participating in the Wildfire Fund should not pay the Wildfire Fund NBC.<sup>34</sup> In setting a total annual revenue requirement for the Wildfire Fund NBC the Commission must take into account only the large electrical corporations that are eligible and elect to participate in the Wildfire Fund. The Commission also agrees with the consensus of the parties on this point.

The Rate Agreement that is adopted by this decision is consistent with the statute and this decision’s implementation of AB 1054. The Rate Agreement is structured to ensure that the revenue requirement for the Wildfire Fund NBC is determined based on historic contributions from the ratepayers of the electrical corporations that participate in the Wildfire Fund. Section 4.1 of the Rate Agreement states that the revenue requirement shall be equal to the average annual amount of collections by DWR with respect to the DWR Bond Charges “on customers of each Large Electrical Corporation that is eligible and elects to participate in the Wildfire Fund.” Section 1.1 of the Rate Agreement defines “Nonbypassable Charges” as a charge imposed on “customers in each of the Service Areas of any Large Electrical Corporation that is eligible and elects to

---

<sup>32</sup> CforAT opening comments at 5-6.

<sup>33</sup> SDG&E opening comments at 12-13. *See also* EPUC opening comments at 11-12; TURN opening comments at 19-20.

<sup>34</sup> *See, e.g.*, Pub. Util. Code §§ 3281(g), 3291(c), and 3292(c).

participate in the Wildfire Fund.” In Section 5.1 of the Rate Agreement, through the Charge Covenant, the Commission agrees to impose non-bypassable charges “sufficient to fund the Revenue Requirement,” which is defined in reference solely to those large electrical corporations participating in the Wildfire Fund. These provisions ensure that ratepayers of participating electrical corporations will not bear any responsibility for the historic DWR Bond Charge contributions from non-participating electrical corporations, and ratepayers of non-participating electrical corporations will not pay the Wildfire Fund NBC.

AB 1054 and the Commission’s interpretation of it, including Public Utilities Code Section 3289 and Water Code Section 80524, are consistent with a memorandum from the Director of DWR to the Executive Director of the Commission dated August 21, 2019. This memorandum explained DWR’s view that the calculation method provided in the Rate Agreement harmonizes the statutory provisions, including the relevant sections of the Water Code, with the overall legislative intent and thus appropriately implements the Wildfire Fund funding mechanism contemplated by AB 1054.<sup>35</sup> The Commission must also consider the statute as a whole and harmonize its various provisions in order to effectuate the intent of AB 1054. This decision’s approval of these terms of the Rate Agreement is consistent with and effectuates the Commission’s interpretation of AB 1054, including Public Utilities Code Section 3289 and Water Code Section 80524.

---

<sup>35</sup> August 21, 2019 ALJ Ruling seeking party comment on proposed Rate Agreement, Attachment 2.

The Commission also holds that, under Public Utilities Code Section 3292, once a large electrical corporation has made its commitment to participate in the Wildfire Fund, then it shall continue to participate in the Wildfire Fund and shall fully satisfy the statutorily required shareholder contributions.<sup>36</sup> AB 1054 contains no provision that allows a large electrical corporation to change its status as a participating utility and as a result the commitment to make annual contributions contained in the statute must be implemented as a binding commitment.

Accordingly, this decision finds that the concerns raised by parties and our conclusion agreeing with their concerns are fully addressed by the manner in which the revenue requirement is calculated, the fact that ongoing participation in the Wildfire Fund is imposed, and the terms of the Rate Agreement adopted by this decision.

#### **4.2.2. Approved Revenue Requirement**

Public Utilities Code Section 3292(b)(1) states that a utility that is subject to an insolvency proceeding, or on criminal probation, must, by June 30, 2020, meet certain criteria in order to participate in the Wildfire Fund. As a result, whether or not the collections of historic DWR Bond Charges from PG&E's ratepayers will be included in the calculation of the revenue requirement for the Wildfire Fund NBC is a question that can only be definitively resolved after June 30, 2020. Accordingly, in light of AB 1054's provisions, the Energy Division's data compilation, comments received from parties on this issue, and the discussion above, the total annual revenue requirement for the Wildfire Fund NBC shall be

---

<sup>36</sup> Pub. Util. Code §§ 3292(b)(3) and 3292(c) specify that no large electrical corporation contributions to the Wildfire Fund may be recovered from ratepayers.

set at the sum of the following amounts collected from customers of each large electrical corporation that is eligible and elects to participate in the Wildfire Fund, not to exceed \$902,400,000:

- \$404,600,000 for historic collections if PG&E participates in the Wildfire Fund.
- \$408,200,000 for historic collections if SCE participates in the Wildfire Fund.
- \$89,600,000 for historic collections if SDG&E participates in the Wildfire Fund.

Pursuant to Water Code Section 80524(a) this annual revenue requirement shall expire at the end of the year 2035.

#### **4.2.3. Impact of Large Electrical Corporation Participation on the Amount of Bonds Issued**

EPUC raised an argument that a total revenue requirement that is smaller than the maximum that would be achieved if all three large electrical corporations participated in the Wildfire Fund should lead to reduced bond issuance by DWR. EPUC states that AB 1054 includes “permissive terms and only caps the total [bond issuance] at \$10.5 billion, allowing the Commission the discretion to authorize a lower amount.”<sup>37</sup>

This claim does not accurately describe the statute. Water Code Section 80540 provides that “bonds may not be issued in an amount the debt service on which... is estimated by the department to exceed the amounts estimated to be available in the fund for their payment.”

As a result, the bond issuance is limited, in addition to the hard cap, by the amount DWR has available for debt service. The Rate Agreement has analogous

---

<sup>37</sup> EPUC opening comments at 13.

provisions stating that the security for any bonds will be the covenant contained in Sections 5.1(a) and 5.1(b), which will be irrevocable. That covenant states that the Wildfire Fund NBC will be “at all time sufficient to fund Revenue Requirement” which section 4.1(a) of the Rate Agreement requires to be calculated based on the average annual collections of past DWR Bond Charges imposed on “customers of each Large Electrical Corporation that is eligible and elects to participate in the Wildfire Fund.” By defining the amounts that can be securitized in this manner, the Rate Agreement effectively limits the size of the bonds to an amount that corresponds to the revenue collected by the Wildfire Fund NBC, taking into account the large electrical corporations that are participating in the Wildfire Fund. The Rate Agreement is therefore consistent with Water Code Section 80540.

## **5. The Commission’s Rate Agreement with the Department of Water Resources**

In this decision the Commission exercises its authority to impose the Wildfire Fund NBC on the ratepayers of electrical corporations participating in the Wildfire Fund, and finds that the imposition of such a charge is just and reasonable. This determination triggers a provision of Water Code Section 80524(b) that requires the Commission to “enter into an agreement with [DWR] with respect to [Wildfire Fund NBC charges] with respect to the revenue requirement, and that agreement shall have the force and effect of an irrevocable financing order... as determined by the commission.” Water Code Section 80524(b) goes on to establish the following requirements for the Rate Agreement:

[P]rovide for the administration of the revenue requirement, including provisions to the effect that (1) the department shall notify the commission each year of the annual collections received by the department with respect to the revenue requirement and the amount of any excess or deficiency in collections above or below the revenue

requirement and that the commission shall adjust charges in the subsequent year to reflect any such excess or deficiency, and (2) during any revenue requirement period if the department forecasts that the revenue requirement for that period will not be met and that collections will not be sufficient to fund any of the amounts in paragraphs (1) to (5), inclusive, of [Water Code] Section 80544, then the department shall notify the commission in writing and the commission shall act within 30 days to increase charges so that the amounts collected during that period are sufficient to meet those obligations. For avoidance of doubt, no such adjustment to charges by the commission shall affect in any respect the commission's just and reasonable determination with respect to the revenue requirement.

A proposed Rate Agreement between the Commission and DWR was submitted to the parties for their review in an ALJ ruling of August 21, 2019. As noted above, a memorandum from DWR was provided in connection with the Rate Agreement. Most parties declined to comment on the proposed Rate Agreement itself, however TURN did recommend modifying the Rate Agreement to address the issue of over- or under-collections.<sup>38</sup> As to collections in any year in excess of the revenue requirement, the Rate Agreement addresses this issue in Section 4.1(c). That requires DWR to annually notify the Commission if the Wildfire Fund NBC collects an amount from ratepayers in excess of the revenue requirement, and further requires the Commission to adjust the Wildfire Fund NBC in the following year to reflect that excess collection.

Because this decision sets the revenue requirement as directed by statute, there is no possibility that the revenue requirement itself will be revisited until 2036. As there will therefore be no adjustment to the revenue requirement based

---

<sup>38</sup> TURN reply comments at 10.

on collections received by DWR in a previous year, there is no reason to modify the Rate Agreement in the manner recommended by TURN.

The table below describes the requirements of Water Code Section 80524(b) and how the provisions of the proposed Rate Agreement satisfy each of those requirements.

| Water Code Section 80524(b) Requirement                                                                                                                                                                                                                                                                                 | Rate Agreement Provision                                                                                                                                                                 |
|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Provide for the administration of the revenue requirement.                                                                                                                                                                                                                                                              | Article IV of the Rate Agreement generally concerns the revenue requirement and its administration.                                                                                      |
| DWR shall notify the Commission annually of the collections received by DWR and the amount of any excess or deficiency in collections above or below the revenue requirement.                                                                                                                                           | Section 4.1(c)-(d) of the Rate Agreement provides for such notification.                                                                                                                 |
| Commission shall adjust Wildfire Fund NBC charges in the subsequent year to reflect any excess or deficiency reported by DWR.                                                                                                                                                                                           | Section 4.1(c) of the Rate Agreement provides for such adjustment.                                                                                                                       |
| DWR shall notify the Commission in writing if during any revenue requirement period if the department forecasts that the revenue requirement for that period will not be met and that collections will not be sufficient to fund any of the amounts in paragraphs (1) to (5), inclusive, of [Water Code] Section 80544. | Section 4.1 of the Rate Agreement provides for such notification and the Commission expects DWR to spell out the shortfalls for any of paragraphs (1) - (5) of Water Code Section 80544. |
| The Rate Agreement shall have the force and effect of an irrevocable financing order as determined by the Commission.                                                                                                                                                                                                   | Section 5.1 of the Rate Agreement                                                                                                                                                        |

Based on the comments received from the parties, the memorandum from DWR, and a review of the proposed Rate Agreement, this decision finds that the

proposed Rate Agreement as submitted to the parties in the ALJ ruling of August 21, 2019, and as modified to make some technical changes, complies with the requirements of Water Code Section 80524(b) and other applicable law. The Rate Agreement should be adopted by the Commission and the provisions in Section 5.1(a) and 5.1(b) should have the force and effect of a financing order as provided in Water Code Section 80524(b). A copy of the modified Rate Agreement as a redline version of the original proposed Rate Agreement attached to the ALJ ruling of August 21, 2019 is attached to this decision as Appendix A. The Commission will execute the attached Rate Agreement as soon as practicable after the issuance of this decision.

## **6. Wildfire Fund NBC Rate Design**

AB 1054 specifies that if the Wildfire Fund NBC is adopted then it should be collected “in the same manner as” the current DWR Bond Charge.<sup>39</sup> Some parties suggested delaying consideration of the design of the Wildfire Fund NBC.<sup>40</sup> This decision determines the design of the Wildfire Fund NBC at this time, instead of in a later phase of this proceeding.

The Commission notes the argument of the Joint CCAs that the words “in the same manner” may be ambiguous.<sup>41</sup> The Commission disagrees and holds that the term “in the same manner” means that the Wildfire Fund NBC should be collected in no different a manner from the DWR Bond Charge.

---

<sup>39</sup> Pub. Util. Code § 3289(a)(2).

<sup>40</sup> CLECA opening comments at 5, Cal Advocates opening comments at 8.

<sup>41</sup> Joint CCAs reply comments at 4.

The existing DWR Bond Charge is collected on a dollar per kWh basis. According to TURN, this charge has averaged approximately half a cent per kWh over the last several years.<sup>42</sup> All customers in all customer classes are required to pay the DWR Bond Charge on an equal cents per kWh basis, with some exceptions as discussed more fully below. As an initial matter, this decision rejects SDG&E's suggestion that the Wildfire Fund NBC be collected as a fixed charge rather than a volumetric charge.<sup>43</sup> SEIA argues that the plain meaning of the phrase "in the same manner as" requires the design of the Wildfire Fund NBC as a volumetric charge.<sup>44</sup>

This decision agrees with SEIA and finds that the Wildfire Fund NBC shall be collected on a dollar per kWh basis to conform with the directive of Public Utilities Code Section 3289(a)(2). Collecting the Wildfire Fund NBC as a fixed charge (presumably on a dollar per customer/month basis) would not collect the charge in the same manner as the DWR Bond Charge.<sup>45</sup>

### **6.1. Wildfire Fund NBC Revenue Allocation**

TURN argues that the allocation of the Wildfire Fund NBC across customer classes should mirror the allocation currently used for the DWR Bond Charge, as deviations from the existing allocation methodology would result in electric rate increases for some customers and arguably violate the statute's terms.<sup>46</sup>

---

<sup>42</sup> TURN opening comments at 7.

<sup>43</sup> SDG&E opening comments at 14.

<sup>44</sup> SEIA reply comments at 4. *See also* CforAT reply comments at 6.

<sup>45</sup> CforAT reply comments at 6.

<sup>46</sup> TURN opening comments at 15.

No party other than TURN specifically addressed the issue of revenue allocation for the Wildfire Fund NBC. TURN claims that the DWR Bond Charge revenue allocation method it describes in comments dates to Commission decisions from 2002, and that the method should be used for the Wildfire Fund NBC. That method assigns the charge to all utility distribution ratepayers, including DA and CCA customers. TURN states that this is appropriate “from an equity and policy perspective” as the Wildfire Fund is “related to the components of utility service that both bundled and unbundled customers receive” from the utilities.<sup>47</sup>

The DWR Bond Charge revenue allocation method assigns the costs of the DWR Bond Charge to each class proportionate to a class’s share of the utility’s kWh sales in a given year. This essentially means a class’s responsibility for the DWR Bond Charge costs is directly proportional to the amount of energy that class consumes. It also has the effect of making the DWR Bond Charge virtually identical on a dollar per kWh basis across classes.

Maintaining the revenue allocation for the Wildfire Fund NBC so that it is no different than the existing revenue allocation for the DWR Bond Charge is equitable and conforms with the statute’s instructions to collect the Wildfire Fund NBC in the same manner as the DWR Bond Charge. For these reasons this decision orders that the Wildfire Fund NBC use the same revenue allocation as the DWR Bond Charge as described above. All customers of a given large electrical corporation shall pay the same amount per kWh for the Wildfire Fund NBC, unless that customer is excluded as ordered below.

---

<sup>47</sup> TURN opening comments at 16.

## **6.2. Exclusions of Certain Customers from the Wildfire Fund NBC**

Parties pointed out that the DWR Bond Charge is not collected from several types of customers. These customers include California Alternate Rates for Energy (CARE) residential customers, Medical Baseline residential customers, and continuous direct access (DA) customers.<sup>48</sup>

### **6.2.1. CARE and Medical Baseline Residential Customers**

TURN maintains that the existing exemptions from the DWR Bond Charge for residential customers that participate in the CARE program and Medical Baseline program should apply to the Wildfire Fund NBC as well. Their argument is grounded in equity and would mirror the current method for collecting the DWR Bond Charge.<sup>49</sup> Joint CCAs also supported the existing CARE and Medical Baseline exemptions.<sup>50</sup> This argument is reasonable and complies with the statute's language.<sup>51</sup> The Wildfire Fund NBC shall not be collected from CARE or Medical Baseline residential customers.

### **6.2.2. Continuous DA Customers and Other Excluded Customers**

Continuous DA customers were exempted from paying the DWR Bond Charge in D.02-11-022 because those customers did not consume the electricity

---

<sup>48</sup> Continuous DA customers are those that have been taking DA service continuously both before and since January 17, 2001 in the PG&E and SCE service territories or February 7, 2001 in SDG&E's service territory.

<sup>49</sup> TURN opening comments at 18-19.

<sup>50</sup> Joint CCAs opening comments at 3.

<sup>51</sup> Pub. Util. Code § 3289(a)(2).

that DWR purchased for utility customers during the height of the energy crisis. As these customers did not consume the electricity purchased by DWR, the Commission reasoned that they should not be obligated to pay the charge that reimbursed DWR for those electricity purchases.<sup>52</sup>

TURN argues that the situation with the Wildfire Fund NBC is distinguishable, as continuous DA customers remain distribution customers of the utilities, and the Wildfire Fund is designed to address liabilities arising from the damages caused by a utility's infrastructure. TURN and Joint CCAs assert that continuous DA customers should be equally responsible for any wildfire liability costs assigned to ratepayers as such customers are served by utility infrastructure that may ignite wildfires.<sup>53</sup>

EPUC sought to maintain the exemption for self-generation customers in order to ensure that the Wildfire Fund NBC is collected in the same manner as the existing DWR Bond Charge.<sup>54</sup>

Whatever the merits of the argument for imposing the Wildfire Fund NBC on continuous DA customers, the statute states that the Wildfire Fund NBC shall be collected in the same manner as the DWR Bond Charge. Without any statutory language to the contrary this decision therefore finds that continuous DA customers should be excluded from paying the Wildfire Fund NBC. This also applies to any other customers currently exempted from the DWR Bond Charge, such as certain customers utilizing customer generation departing load (CGDL) as defined by D.03-04-030.<sup>55</sup>

---

<sup>52</sup> D.02-11-022 at 60.

<sup>53</sup> TURN opening comments at 16-17; Joint CCAs opening comments at 6.

<sup>54</sup> EPUC reply comments at 3.

<sup>55</sup> Joint CCAs opening comments at 6; CLECA reply comments at 8.

### **6.2.3. Net Energy Metering Customers**

While net energy metering (NEM) customers are not per se excluded from paying the DWR Bond Charge, NEM customers may substantially reduce their DWR Bond Charge payments by reducing their net usage of electricity.

Customers taking service on the original NEM tariff as it existed before the creation of the successor NEM tariff in D.16-01-044 pay for the DWR Bond Charge on any net usage over the course of the year. Customers taking service on the NEM successor tariff created by D.16-01-044 (informally known as NEM 2.0) pay for the DWR Bond Charge on any net usage within a metered interval.<sup>56</sup>

TURN and other parties seek clarification from the Commission on how the Wildfire Fund NBC would apply to NEM customers, in particular whether the Wildfire Fund NBC would be a non-bypassable charge that would apply to NEM 2.0 customers in the same way as the DWR Bond Charge.

As with the discussion surrounding continuous DA customers, the statute states that the Wildfire Fund NBC should be collected in the same manner as the DWR Bond Charge. For that reason, large electrical corporations imposing the Wildfire Fund NBC on their customers shall apply the Wildfire Fund NBC to their NEM customers in the same manner as the DWR Bond Charge is currently imposed. Consistent with the Commission's previous treatment of NEM customers, the Commission may modify the calculation of the consumption on which non-bypassable charges are assessed for NEM customers.

---

<sup>56</sup> For residential customers the metered interval is one hour and for non-residential customers the metered interval is 15 minutes.

#### **6.2.4. Exclusions for Customers of Regional Electrical Corporations**

The language of Public Utilities Code Section 3289(a)(2) requires the Wildfire Fund NBC to be collected “in the same manner” as the DWR Bond Charge if the Commission directs “each electrical corporation to impose and collect” the Wildfire Fund NBC.

If a regional electrical corporation elects to participate in the Wildfire Fund and impose the Wildfire Fund NBC on its ratepayers, there is no current method of collecting the DWR Bond Charge for regional electrical corporation customers that can be used as a basis for determining the method for collecting the Wildfire Fund NBC. The language of Public Utilities Code Section 3289(a)(2) therefore does not guide the Commission in determining whether the current DWR Bond Charge exclusions for large electrical corporation customers should apply to regional electrical corporation customers.

The most reasonable solution is to apply the same customer exclusions to regional electrical corporation ratepayers as are applied to large electrical corporation ratepayers. This would avoid the result where, for example, CARE customers in SCE’s territory would avoid paying the Wildfire Fund NBC while neighboring CARE customers in Bear Valley’s territory would be required to pay the Wildfire Fund NBC. Such a result would be inequitable. For this reason, if a regional electrical corporation elects to participate in the Wildfire Fund and impose the Wildfire Fund NBC on its customers, the same Wildfire Fund NBC exclusions as apply to large electrical corporation customers shall apply to the regional electrical corporation’s customers. For NEM customers of regional electrical corporations, the Wildfire Fund NBC shall apply in the same manner as other non-bypassable charges, such as the public purpose program (PPP) charge.

The Commission notes that this issue may be moot as all regional electrical corporations have indicated that they will not participate in the Wildfire Fund.

### **6.3. Establishing an Annual Wildfire Fund NBC Process**

With respect to the existing DWR Bond Charge, the kWh sales forecasts and the annual revenue requirement are set during an annual proceeding. Such a model would be useful here as well in order to clarify on an annual basis the exact \$/kWh charge that will be imposed on ratepayers of large electrical corporations.

The Commission keeps the instant proceeding open in order to consider the annual revenue requirement and sales forecast for the Wildfire Fund NBC in 2020. The final month in which the DWR Bond Charge will be collected is unknown at this time, but it may be as early as the second half of 2020. For these reasons, the Commission sets out the following process for designing and approving the Wildfire Fund NBC for 2020:

- 90 days prior to the expected date of imposition of the Wildfire Fund NBC, DWR is requested to transmit to the Commission and the large electrical corporations a preliminary “Proposed Determination of Wildfire Fund Non-Bypassable Charge” for the remainder of 2020 with the following estimated information:  
1) notice of the month of termination of the DWR Bond Charge based on the date of defeasance of the DWR Bonds, and the first month for imposition of the Wildfire Fund NBC, 2) the pro-rated revenue requirement consistent with this decision, the Rate Agreement, and AB 1054,<sup>57</sup> 3) the electricity sales forecast for all anticipated participating large electrical corporations for the months in 2020 when the Wildfire Fund NBC will be imposed,

---

<sup>57</sup> Water Code Section 80524(a) requires a pro rata revenue requirement for the first and last year of the Wildfire Fund’s operation. This means that in the event the Wildfire Fund NBC is imposed for part of 2020, the revenue requirement for 2020 will be pro rated according to the portion of the year the Wildfire Fund NBC is imposed.

and 4) DWR's calculation of the resulting Wildfire Fund NBC for customers subject to the Wildfire Fund NBC pursuant to this decision.

- 60 days prior to the expected date of imposition of the Wildfire Fund NBC, or earlier if possible, DWR is requested to make its "Proposed Determination of Wildfire Fund Non-Bypassable Charge" final.
- The ALJ assigned to this proceeding will, via ruling, notify parties of receipt of the DWR's "Proposed Determination of Wildfire Fund Non-Bypassable Charge" and seek comment on the same.
- After receiving party comments the ALJ will draft a proposed decision adopting the Wildfire Fund NBC for the months in 2020 when the Wildfire Fund NBC will be imposed.

For every year after 2020, an annual Wildfire Fund NBC charge determination process shall be considered in future Commission decisions.

## **7. It is Just and Reasonable to Impose the Wildfire Fund NBC**

The preceding discussion in this decision establishes the scope of the Commission's legal authority to require the collection of a new Wildfire Fund NBC, defines the statutorily mandated design of the Wildfire Fund NBC, and determines the revenue it shall collect. This allows the Commission to answer the final question raised in this proceeding, namely whether it is just and reasonable to impose the Wildfire Fund NBC on the customers of California's investor-owned electric utilities.

As an initial matter, the Legislature and the Governor determined that the creation of the Wildfire Fund furthers state policy goals and benefits ratepayers.<sup>58</sup> The legislative findings supporting this determination are as follows:

---

<sup>58</sup> AB 1054, Section 1(b).

- That there is an increased risk of catastrophic wildfires and that there are increased costs to ratepayers as a result of that increased risk. These increased costs are attributable to the exposure of electrical corporations to financial liability resulting from wildfires that are caused by utility equipment.<sup>59</sup>
- That the creation of the Wildfire Fund will reduce costs to ratepayers in addressing utility-caused catastrophic wildfires.<sup>60</sup>
- That the establishment of the Wildfire Fund supports the credit worthiness of electrical corporations, and provides a mechanism to attract capital for investment in safe, clean, and reliable power for California at a reasonable cost to ratepayers.<sup>61</sup>

AB 1054 also added Section 80503(a) to the Water Code, which specified that the “development and operation of a program as provided in [Division 28 of the Wildfire Prevention and Recovery Act of 2019] is in all respects for the welfare and benefit of the people of the state, to protect the public peace, health, and safety, and constitutes an essential government purpose.”

Based on these legislative determinations, and the record of this proceeding, the Commission determines that the imposition of the Wildfire Fund NBC created by AB 1054 is just and reasonable as discussed in more detail below.

### **7.1. Public Policy Findings of the Legislature**

The Commission notes that the Legislature made clear findings in AB 1054 that the public policy interests of the state of California are served by the Wildfire Fund. In particular, the Legislature found that it was a public policy goal to “attract capital for investment in safe, clean, and reliable power for

---

<sup>59</sup> AB 1054, Section 1(a)(1), (2).

<sup>60</sup> AB 1054, Section 1(a)(3).

<sup>61</sup> AB 1054, Section 1(a)(4)&(5).

California at a reasonable cost to ratepayers” by way of creating the Wildfire Fund.<sup>62</sup>

The Legislature has determined that it is in the public interest to establish the Wildfire Fund and create a detailed construct for managing future wildfire claims as defined by AB 1054. The Commission finds that imposing the Wildfire Fund NBC is in the public interest as it supports the framework for managing future wildfire claims via the Wildfire Fund established by AB 1054. This finding supports this decision’s determination that imposing the Wildfire Fund NBC is just and reasonable.

## **7.2. The Wildfire Insurance Fund Protects Ratepayers from Liability Attached to Wildfires Caused by a Utility**

An important element of the insurance framework of the Wildfire Fund established in Public Utilities Code Section 3292, and overlooked by several parties to this proceeding, is that the capital held by the Wildfire Fund to pay eligible claims for covered wildfires is contributed to by both ratepayers and shareholders. For example, in one scenario the Wildfire Fund could be capitalized at a total amount of approximately \$21 billion from approximately equal contributions by participating electrical corporations’ shareholders and bonds financed by a dedicated non-bypassable charge collected from ratepayers.<sup>63</sup> The amount of insurance products and cash financed from this

---

<sup>62</sup> *Id.*

<sup>63</sup> DWR and the Wildfire Fund have the ability to choose from several different statutorily defined ways to treat the capital they receive; however this example shows how shareholder and ratepayers both contribute to the Wildfire Fund. *See* Ins. Code § 10089.7; Water Code § 80554(a).

\$21 billion in proceeds will pay eligible wildfire claims where the electrical corporation is found to have acted prudently.<sup>64</sup>

As such, AB 1054's framework essentially provides an insurance fund that protects ratepayers from future recovery in rates for prudently incurred utility wildfire costs for which ratepayers might otherwise be responsible to pay in full. Some parties argue that ratepayers may be forced to pay for eligible claims already paid for by the Wildfire Fund.<sup>65</sup> As discussed more fully below, this argument is incorrect. This decision finds that the shareholder contributions to the insurance structure of the Wildfire Fund provides benefits to ratepayers. It may be true that electrical corporations could potentially rely on the Wildfire Fund to pay a portion of imprudently incurred wildfire claims should the utility's costs exceed the statutorily mandated cap on utility reimbursement. Nevertheless, on balance, this possibility does not undermine this decision's finding that the electrical corporations' shareholder contributions to the Wildfire Fund benefit ratepayers.

The Commission finds that the directive of Public Utilities Code Section 451.1 that "the commission shall allow cost recovery if the costs and expenses are just and reasonable" in a catastrophic wildfire proceeding is satisfied by the payment of costs prudently incurred by the electrical corporation that are paid from the Wildfire Fund. This means that "cost recovery" as defined

---

<sup>64</sup> CCUE opening comments at 7-8; SDG&E opening comments at 7-8 ("[b]oth ratepayers and utilities benefit from the Wildfire Fund, as structured in AB 1054. If a utility is found to have acted prudently under [Pub. Util. Code] Section 451.1, it can tap the Wildfire Fund to pay for wildfire damages, and no reimbursements are due to the fund. [citation omitted] Prior to AB 1054, however, if the utility was deemed prudent, ratepayers would have had to pay for those wildfire damages in their entirety") (emphasis original).

<sup>65</sup> Cal Advocates opening comments at 12; SCE opening comments at 5; EPUC opening comments at 5-6.

by Public Utilities Code Section 451.1 has already occurred when the eligible wildfire claim is paid by the Wildfire Fund.

As discussed further below, this decision finds that ratepayers will not reimburse the Wildfire Fund for withdrawals used to pay prudently incurred eligible wildfire claims. This finding is consistent with Public Utilities Code Section 1701.8(b)(4)(A) defining the scope of a catastrophic wildfire proceeding to be whether the electrical corporation's costs and expenses are just and reasonable.

### **7.3. Financial Stability of Electrical Corporations and Reduced Financing Costs**

The Wildfire Fund will likely improve electrical corporations' financial stability and lower their financing costs. Uncertainty about cost recovery for wildfire liabilities, led to credit rating downgrades for SCE and SDG&E in 2019.<sup>66</sup> These utilities accounted for these downgrades in applications seeking significant increases to their requested return on equity – a cost that is ultimately passed on to ratepayers.<sup>67</sup>

For example, SCE reports that in March 2018 it was able to issue a “low double A-rated” secured bond with an interest rate of 4.125%. In March 2019, subsequent to SCE's credit rating downgrade, SCE was able to issue a “low single A-rated” secured bond with an interest rate of 4.875%. Even though the 30-year U.S. Treasury bond yield had declined 0.15% in that period of time,

---

<sup>66</sup> CCUE opening comments at 6.

<sup>67</sup> SDG&E opening comments at 7, 11; SCE reply comments at 4, fn 11 (“[o]nce a [credit] downgrade has been issued it can take years to reverse, and SCE's customers will incur higher borrowing costs until the ratings agencies moved [sic] to restore SCE's ratings to prior levels”); *see also* Application 19-04-014, et al.

investors required an additional 0.75% in yield from SCE in exchange for financing SCE's debt. SCE asserts that increased costs to ratepayers from the March 2019 bond issuance as compared to the March 2018 bond issuance will be approximately \$200 million over the life of the March 2019 bonds.<sup>68</sup>

Beyond the credit downgrades experienced by SCE and SDG&E, the utilities stated in comments that they faced a threat of continuing downgrades in the future – and attendant increases in ratepayer costs to finance utility investments – absent a solution such as the structure imposed by AB 1054.<sup>69</sup> TURN grants that “ratings agencies have all viewed AB 1054 as a credit positive for the utilities.”<sup>70</sup>

Cal Advocates does not dispute the possibility of further downgrades identified in the utilities' comments, but disagrees that the lack of a credit downgrade should be considered a ratepayer benefit, and instead reasons that the absence of an improvement in the credit ratings of SDG&E and SCE after the passage of AB 1054 indicates that ratepayer costs are not being lowered.<sup>71</sup> In response to this argument, SDG&E and SCE point out that their asserted ratepayer benefit in this context is the prevention of a decline in credit ratings for SDG&E and SCE attributable to AB 1054 rather than an improvement in credit

---

<sup>68</sup> SCE reply comments at 4-5.

<sup>69</sup> SDG&E reply comments at 9.

<sup>70</sup> TURN opening comments at 19.

<sup>71</sup> Cal Advocates opening comments at 16-17.

ratings.<sup>72</sup> SCE claims that “avoiding future credit downgrades will save customers money.”<sup>73</sup>

These reduced risks of credit downgrades attributable to AB 1054 have the potential to result in reduced ratepayer costs in open Commission proceedings. SCE reduced its requested return on equity and resulting revenue requirement by \$1 billion in its cost of capital proceeding (Application (A.) 19-04-014) as a direct response to the establishment of the Wildfire Fund and SCE’s participation in it.<sup>74</sup> PG&E reduced its requested return on equity in A.19-04-015 from 16% to 12% due to the effect of AB 1054 and the potential Wildfire Fund NBC.<sup>75</sup> SDG&E reduced its requested return on equity in A.19-04-017 from 14.3% to 12.38% in light of AB 1054’s passage.<sup>76</sup> TURN and CLECA both argue against assuming that the positions of the electrical corporations reflect actual reductions in ratepayer costs, given that these proceedings are being actively litigated.<sup>77</sup>

No party disputed the factual assertions of SCE and SDG&E with respect to their actual and potential credit downgrades. No party disputed that credit agencies generally viewed AB 1054 as a positive development for the credit risks presented by SDG&E and SCE. TURN and CLECA argue that factual questions regarding a utility’s cost of capital should be litigated in the appropriate

---

<sup>72</sup> SDG&E reply comments at 8-9; SCE reply comments at 4.

<sup>73</sup> SCE reply comments at 5.

<sup>74</sup> *Id.*

<sup>75</sup> PG&E opening comments at 7, noting that their testimony in A.19-04-015 is subject to numerous assumptions and uncertainties.

<sup>76</sup> SDG&E reply comments at 8, fn 28.

<sup>77</sup> CLECA reply comments at 9-10.

proceeding.<sup>78</sup> While this argument by TURN and CLECA is noted, this decision holds that the credit ratings of SCE and SDG&E were generally stabilized by AB 1054, and all else being equal, the prevention of credit rating downgrades for electrical corporations reduces ratepayer costs.

The facts support a conclusion that the passage of AB 1054 and the existence of the Wildfire Fund have a positive impact of the credit risks of the state's electrical corporations and help to reduce ratepayer costs related to utility financing.

#### **7.4. Other Opposing Positions**

In addition to opposing to the revenue requirement and imposition of the Wildfire Fund NBC noted above, several parties raised other arguments for why imposing the Wildfire Fund NBC is not just and reasonable

##### **7.4.1. Due Process**

Several parties claimed that the process used to consider the issues in this proceeding is deficient and unlawful. These parties argue that the lack of due process means that this decision cannot find that the Wildfire Fund NBC is just and reasonable.

Cal Advocates notes that the usual timeframe for Commission proceedings considering ratesetting issues of this magnitude is 18 months, as opposed to the compressed 90-day timeframe used in this proceeding.<sup>79</sup>

---

<sup>78</sup> TURN reply comments at 10; CLECA reply comments at 9-10.

<sup>79</sup> Cal Advocates opening comments at 8, citing *Mathews v. Eldridge* (1976) 424 U.S. 319, 333.

UCAN contends that not enough time is granted to parties to develop an evidentiary record to determine the quantity and nature of a non-bypassable charge that would be “appropriate” to levy on residential ratepayers.<sup>80</sup>

Ruth Henricks alleges various inadequacies with the process used in this proceeding, including: a lack of opportunity for parties to meaningfully consider the issues, a denial of evidentiary hearing, releasing a proposed Rate Agreement for party review eight days before the due date for opening comments, alleged deficiencies in the fact-finding process caused by taking official notice of state-sponsored reports,<sup>81</sup> and insufficient fact-finding in general.<sup>82</sup>

Wild Tree Foundation insists that the process used in this proceeding does not comply with the requirements of the California Constitution, the Constitution of the United States, the Public Utilities Code, and the Rules, particularly with respect to takings, notice, and an opportunity to be heard.<sup>83</sup> Wild Tree Foundation also argues that the lack of evidentiary hearing, lack of record development, lack of legal briefing, and lack of meaningful opportunity to comment means there is an inadequate factual record to determine whether the Wildfire Fund NBC is just and reasonable.<sup>84</sup>

The OIR commencing this proceeding was made publicly available in advance of its consideration at a public meeting of the Commission on July 26, 2019. The agenda announcing that the OIR would be under consideration was

---

<sup>80</sup> UCAN opening comments at 2-3.

<sup>81</sup> Henricks opening comments at 4.

<sup>82</sup> Henricks opening comments at 5, 19.

<sup>83</sup> Wild Tree Foundation opening comments at 1-2.

<sup>84</sup> Wild Tree Foundation opening comments at 2, 5.

published timely in advance on July 16, 2019. After the OIR was approved by the Commission, it was served on the service lists for dozens of Commission proceedings as well as multiple other parties and agencies that were determined to have an interest in the proceeding.<sup>85</sup>

The PHC was noticed in the OIR adopted on July 26, 2019 and on the Commission's Daily Calendar. Informal notices were also sent to the service lists for dozens of Commission proceedings. All entities present at the PHC were afforded the opportunity to comment on the proposed scope and schedule of the proceeding. There are 31 parties to this proceeding and many parties filed opening and reply comments. While the schedule is admittedly expedited compared to other Commission proceedings, parties were granted substantial notice of the proceeding and were afforded an opportunity to research and develop positions on scoped issues, prepare and submit opening comments, and then file a second round of responsive comments. Parties were able to present those issues they saw fit to address in their comments as well as respond to issues specifically called to their attention for comment. Parties were provided with a proposed Rate Agreement and a document from DWR for their review and discussion in their comments. Many of these parties took advantage of these opportunities and meaningfully engaged in the issues considered by this decision.

Further, parties concerned with the expedited process in this proceeding fail to demonstrate that there are any material issues of disputed fact that require evidentiary hearing, despite their claims to the contrary. For example, Wild Tree

---

<sup>85</sup> Assigned Commissioner's Scoping Memo and Ruling at 10-13.

Foundation argues that the impact of the Wildfire Fund NBC on ratepayer bills is an issue of fact that requires greater deliberation than provided in this proceeding.<sup>86</sup> However, Wild Tree Foundation also points out that Public Utilities Code Section 3289 limits “what precisely [the Commission] can approve: it can approve a rate increase for large electrical corporations equal to an amount sufficient to fund the revenue requirement, as established pursuant to Section 80524 of the Water Code,” and \$0.005/kWh for regional electrical corporation customers.<sup>87</sup>

Wild Tree Foundation grants that there is no dispute as to the nature of the non-bypassable charge that can be approved (or not approved). Therefore, there is no material dispute about the approximate magnitude of the bill impact of such a charge. The Commission is aware of these potential bill impacts and considers them, as detailed below, in its approval of the Wildfire Fund NBC. The Commission imposes the Wildfire Fund NBC in the same manner as the DWR Bond Charge in compliance with the law and to mitigate the bill impact of the imposition of the Wildfire Fund NBC.

Other issues related to the determination of whether the Wildfire Fund NBC is just and reasonable are legal in nature and require review and implementation of AB 1054 rather than a factual determination.<sup>88</sup> Party comments on the meaning and proper interpretation of AB 1054 are extensive.

---

<sup>86</sup> Wild Tree Foundation opening comments at 8-9.

<sup>87</sup> Wild Tree Foundation opening comments at 7.

<sup>88</sup> For example, Wild Tree Foundation’s assertion that a hearing is required to answer the question of whether continuous DA customers should pay the Wildfire Fund NBC (*see* Wild Tree Foundation reply comments at 7) is a question of statutory interpretation with respect to the meaning of the phrase “in the same manner as” as it appears in Pub. Util. Code § 3289(a)(2). An evidentiary hearing would not clarify the answer to this question any more than party comments.

While formal briefing was not required in this proceeding, few restrictions were placed on the parties' ability to provide comments in a form of their choosing, and the majority of the party comments are substantially similar to legal briefing on issues of AB 1054 interpretation and implementation, and therefore provide a reasonable basis for the Commission's decision. For all these reasons, this decision finds that due process was provided in this proceeding.

#### **7.4.2. Ratepayer Reimbursements of Wildfire Fund Withdrawals**

Parties developed contradictory arguments regarding the potential obligation of ratepayers to reimburse the Wildfire Fund for eligible wildfire claims later found to be caused by a prudent utility.

SCE claims that ratepayers are required to reimburse the Wildfire Fund for wildfire costs that are subsequently determined by the Commission to be just and reasonable.<sup>89</sup> Cal Advocates makes a similar assertion that a utility may receive rate recovery for just and reasonable costs and therefore ratepayers will contribute twice to wildfire costs – once through the Wildfire Fund NBC and a second time to the utility for reimbursement to the Wildfire Fund for cost recovery authorized as just and reasonable.<sup>90</sup>

On the other hand, SDG&E posits that ratepayers do not reimburse the Wildfire Fund for costs found to be just and reasonable and that only utility shareholders are required to reimburse the Wildfire Fund for disallowed costs,

---

<sup>89</sup> SCE opening comments at 3 (ratepayers "will only have to repay the Wildfire Fund if the costs are found to be just and reasonable").

<sup>90</sup> Cal Advocates opening comments at 12.

up to a cap.<sup>91</sup> CCUE claims that the Wildfire Fund NBC insulates ratepayers from wildfire liabilities because costs will be recovered from the Wildfire Fund, not as expenses in rates, and thus the Wildfire Fund acts as an insurance policy to pay claims that would otherwise be paid by ratepayers.<sup>92</sup>

This decision's determination that the Wildfire Fund NBC is just and reasonable is based on several considerations, including the potential imposition of double payments by utility ratepayers for the same eligible wildfire claim.<sup>93</sup> This is a question that can be resolved by reference to the statute.

This decision concludes as a matter of law that AB 1054 does not require ratepayers to reimburse the Wildfire Fund or an electrical corporation for eligible wildfire claims paid by the Wildfire Fund that are later determined to be just and reasonable. As described below, this decision rejects the assertion that a utility would be allowed in a future proceeding to recover from ratepayers payments that the utility received to satisfy claims from the Wildfire Fund.

The interpretation of AB 1054 offered by Cal Advocates and SCE regarding reimbursement of the Wildfire Fund, and in particular Cal Advocates' assertions of the potential for double cost recovery, misread AB 1054 because they fail to distinguish between the Wildfire Liquidity Fund and the Wildfire Insurance

---

<sup>91</sup> SDG&E opening comments at 8.

<sup>92</sup> CCUE opening comments at 7-8.

<sup>93</sup> It would not be a "double" payment if ratepayers were required to reimburse the Wildfire Fund for an eligible wildfire claim later found to be just and reasonable. As a large portion of Wildfire Fund assets will come from utility shareholders, and given that funds from various utility ratepayers would be co-mingled, it is more accurate to say that a utility's ratepayers could be made to pay "more than once" for the same eligible claim if SCE and Cal Advocates are to be believed.

Fund. These parties further insert their own interpretation of the statute when they make assumptions on the source of a utility's recovery of prudently incurred wildfire costs. In reading and implementing the statute, the Commission must interpret the statute as a whole and harmonize the various parts of the statute to ascertain the intent of the Legislature and effectuate the purpose of the law.<sup>94</sup>

AB 1054 sets forth two alternate paths to address catastrophic wildfire claims,<sup>95</sup> either through operation of the Wildfire Liquidity Fund pursuant to section 3291, or the Wildfire Insurance Fund pursuant to section 3292. Here we are concerned with the Wildfire Insurance Fund, not the Wildfire Liquidity Fund, as the large electrical corporations have indicated their choice or intention to participate in the Wildfire Insurance Fund.<sup>96</sup> Therefore, when this decision

---

<sup>94</sup> *Alford v. Superior Court (People)* (2003) 29 Cal.4th 1033, 1040 ("Our role in construing a statute is to ascertain the intent of the Legislature so as to effectuate the purpose of the law. Because the statutory language is generally the most reliable indicator of that intent, we look first at the words themselves, giving them their usual and ordinary meaning. We do not, however, consider the statutory language in isolation, but rather examine the entire substance of the statute in order to determine the scope and purpose of the provision, construing its words in context and harmonizing its various parts") (internal citations omitted). *See also* *Cal. Manufacturers Assn. v. Public Utilities Commission* (1979) 24 Cal. 3d 836, 844.

<sup>95</sup> Catastrophic wildfire claims are those third-party claims for damages against an electrical corporation resulting from wildfire ignited on or after July 12, 2019, caused by an electrical corporation as determined by the governmental agency responsible for determining causation, exceeding electrical corporation's insurance coverage or \$1 billion in aggregate in any calendar year, whichever is greater. Pub. Util. Code §§ 1701.8(a)(1), 3280(f).

<sup>96</sup> SCE Notice re Initial Contribution to the Wildfire Fund, served September 11, 2019; SDG&E Notice of Initial Contribution to the Wildfire Fund, served September 11, 2019; PG&E Notice Concerning Its Initial Contribution to the Wildfire Fund, served September 11, 2019. Per the terms of Pub. Util. Code § 3291(g), once the large electrical corporations make timely payment of initial contributions pursuant to Pub. Util. Code § 3292, the Wildfire Liquidity Fund is rendered inoperative as a liquidity fund, and the Wildfire Liquidity Fund becomes the Wildfire Insurance Fund.

refers to the Wildfire Fund it is referring to the Wildfire Insurance Fund established pursuant to Public Utilities Code Section 3292.

When the Wildfire Fund is operative, AB 1054 allows a utility to access the Wildfire Fund to pay eligible wildfire claims quickly, and then commence a proceeding at the Commission (hereinafter a catastrophic wildfire proceeding) that, among other things, determines what amount, if any, utility shareholders must return to the Wildfire Fund as a reimbursement. When the Wildfire Fund is operative, a utility is only required to reimburse claims paid by the Wildfire Fund for “costs and expenses the commission determined were disallowed pursuant to Section 1701.8” subject to a cap.<sup>97</sup>

Costs and expenses initially paid for by the Wildfire Fund, and that the Commission later deems just and reasonable in a catastrophic wildfire proceeding, are not subject to reimbursement to the Wildfire Fund. The Commission therefore concludes as a matter of law that these costs and expenses initially paid for by the Wildfire Fund, and later determined to be just and reasonable in a catastrophic wildfire proceeding by the Commission, are to be exclusively borne by the Wildfire Fund while the Wildfire Fund is operational. Accordingly, the utility recovers the eligible wildfire claims from the Wildfire Fund, not ratepayers, if the Commission determines the utility acted prudently. This interpretation follows the plain language of AB 1054.<sup>98</sup>

This reading of the statute is fully consistent with the legislative history. An analysis prepared for the Assembly Committee on Utilities and Energy states:

---

<sup>97</sup> Pub. Util. Code § 3292(h).

<sup>98</sup> The Legislature chose this path for the now inoperative Wildfire Liquidity Fund. *See* Pub. Util. Code § 3291(d). The lack of such a provision for the Wildfire Insurance Fund is dispositive on its own and the contrasting treatment in the statute confirms this decision’s interpretation.

“[s]pecifically, participating electrical [corporations’] expenses deemed just and reasonable would be recovered from the fund, while costs not deemed just and reasonable would be capped up to an amount equivalent to a cap on 20 percent of the [electrical corporation’s] transmission and distribution equity rate base...”<sup>99</sup> Other extrinsic aids also corroborate this reading of the statute.<sup>100</sup>

AB 1054 also established a new type of commission proceeding – a catastrophic wildfire proceeding – to govern utility applications to recover costs and expenses if the utility has drawn amounts from the Wildfire Fund to pay eligible claims.<sup>101</sup> Public Utilities Code Section 1701.8 directs a utility that has received payments from the Wildfire Fund for third-party damage claims to file an application pursuant to Public Utilities Code Section 451.1 (for covered wildfires) within specific time periods. Section 1701.8 establishes a procedural vehicle for determining whether costs paid from the Wildfire Fund must be paid back to the Wildfire Fund by utility shareholders, or are recovered from the Wildfire Fund itself under Public Utilities Code Section 3292. The catastrophic wildfire proceeding, as indicated by the legislatively determined scope, does not itself authorize rate recovery of wildfire costs paid by the Wildfire Fund. Public Utilities Code Section 451.1 establishes specific standards for the Commission’s review of the utility’s conduct in an application to recover costs and expenses

---

<sup>99</sup> Assembly Committee on Utilities and Energy for hearing date of July 10, 2019, Analysis at 14. *See also* Senate Committee on Energy, Utilities and Communications for hearing date of July 8, 2019, Analysis at 15; Senate Rules Committee third reading, Analysis at 10.

<sup>100</sup> Office of Planning and Research, Final Report of the Commission on Catastrophic Wildfire Cost and Recovery (June 17, 2019), Appendix II at 14 (“all wildfire expenses will be recovered from the fund, not as expenses in rates”).

<sup>101</sup> Pub. Util. Code §§ 451.1(d), 1701.8.

arising from a “covered wildfire”<sup>102</sup> that supplant the Commission’s ordinary just and reasonable standard set forth in Public Utilities Code Section 451.<sup>103</sup> While Public Utilities Code Section 451.1 directs that the Commission “shall allow cost recovery if the costs and expenses are just and reasonable,”<sup>104</sup> this must be read in the context of Public Utilities Code Section 1701.8 itself. Public Utilities Code Section 1701.8(b)(4)(A) requires that the scoping memorandum issued in the catastrophic wildfire proceeding “states that the scope of the proceeding shall be whether the electrical corporation’s costs and expenses for the covered wildfire are just and reasonable pursuant to Section 451 or 451.1, as applicable.”

Accordingly, the Wildfire Fund NBC authorized by this decision, which will be in an amount sufficient to support the annual revenue requirement established by this decision, constitutes the only payments ratepayers will be required to make for eligible wildfire claims paid from the Wildfire Fund.

#### **7.4.3. Alleged Disincentives for Safe Utility Operation**

Several parties asserted that the imposition of the Wildfire Fund NBC and its support for the Wildfire Fund would reduce the incentives for electrical

---

<sup>102</sup> Covered wildfire includes any wildfire ignited on or after July 12, 2019 and caused by the utility. *See* Pub. Util. Code § 1701.8(a)(2).

<sup>103</sup> Pub. Util. Code § 451.1(a)(1) (defining a covered wildfire); Pub. Util. Code § 451.1(b) (enumerating standards for evaluating the conduct of the utility to determine if costs and expenses are just and reasonable); Pub. Util. Code § 451.1(c) (establishing a burden of proof); Pub. Util. Code § 451.1(e) (noting that Pub. Util. Code § 451.1 shall direct the Commission’s evaluation of application for recovery of costs and expenses arising from a covered wildfire).

<sup>104</sup> As previously determined in this decision, if an eligible wildfire claim is paid out of the Wildfire Fund then the electrical corporation has already received “cost recovery” for that claim and may not seek ratepayer reimbursement for that claim in a catastrophic wildfire proceeding.

corporations to maintain safe infrastructure.<sup>105</sup> On this basis they argue that the Wildfire Fund NBC is not just and reasonable. These arguments generally asserted that the Wildfire Fund, through its provision of ratepayer funds for timely resolution of eligible wildfire claims, reduces an electrical corporation's incentives to safely manage its systems.

Specifically, Ruth Henricks and Cal Advocates refer to the Commission's rejection of a previous application for a utility balancing account to settle wildfire claims, and its findings concerning the safe operation of utility infrastructure, as evidence that the Commission has considered this dynamic in the past and relied on it to reject a ratepayer-backed wildfire insurance fund.<sup>106</sup>

Party comments accurately distinguish the Wildfire Fund from the balancing account proposed by A.09-08-020 for several reasons. First, the Wildfire Fund will be capitalized by ratepayer funds and shareholder funds, meaning that a utility's shareholders are contributing to the financial settlement of claims paid by the Wildfire Fund, regardless of whether they could have been fully recovered in rates absent AB 1054. The balancing account at issue in A.09-08-020 would only have made ratepayers liable for wildfire costs.<sup>107</sup> This distinguishing feature of the Wildfire Fund also mitigates the arguments made by some parties that the Wildfire Fund will incent unsafe behavior by the electrical corporations. Because the Wildfire Fund makes shareholders pay for

---

<sup>105</sup> Wild Tree Foundation PHC statement at 8; Henricks PHC statement at 6-7; UCAN PHC statement at 4-5; Wild Tree Foundation opening comments at 9; Henricks opening comments at 15; Cal Advocates opening comments at 13-15.

<sup>106</sup> Henricks opening comments at 13-15; Cal Advocates opening comments at 13-15.

<sup>107</sup> See generally SDG&E reply comments at 5; CCUE reply comments at 9.

claims even if they were prudently incurred costs, the Wildfire Fund does not present the same issue of concern as the balancing account at issue in

A.09-08-020.<sup>108</sup>

SCE lists several features of the Wildfire Fund framework that create incentives for electrical corporations to safely manage their systems. These include shareholder reimbursement of the Wildfire Fund in the event an electrical corporation's behavior is found to be imprudent, combined shareholder contributions to the Wildfire Fund in the amount of \$10.5 billion (assuming PG&E's participation), elimination from an electrical corporation's equity rate base of the first \$5 billion worth of wildfire risk mitigation capital investments, ongoing investments in safety measures as required by approved wildfire mitigation plans, and prohibitions on diversion of authorized revenues to implement wildfire mitigation plans.<sup>109</sup>

SCE highlights that the risk of shareholder reimbursement of the Wildfire Fund, even if capped, incents safe behavior, stating that the "risk of reimbursing the Wildfire Fund for billions of dollars with no recovery from customers creates a powerful incentive for [electrical corporations] to reduce wildfire risk as rapidly and effectively as possible."<sup>110</sup>

The position of SCE and other parties is logical and demonstrates that there is shareholder liability for eligible wildfire claims paid by the Wildfire Fund that are incurred through either prudent or imprudent utility behavior. This decision therefore does not agree with parties that argue the Wildfire Fund

---

<sup>108</sup> SDG&E reply comments at 3-4; CCUE reply comments at 7.

<sup>109</sup> SCE reply comments at 2.

<sup>110</sup> *Id.*

is similar to a solely ratepayer-backed balancing account that may disincentivize safe utility operation.

There are numerous elements of AB 1054 beyond the Wildfire Fund that will keep utility shareholders motivated to ensure safe operation by the utility. Among other things, under AB 1054 utilities must comply with detailed wildfire mitigation plans, as well as enhanced safety requirements developed by the new wildfire safety division. Moreover, in order to participate in the Wildfire Fund, utilities must demonstrate that they are in compliance with the findings of its most recent safety culture assessment, and also that they have an executive compensation scheme in place that is tied to their safety performance. Importantly, the Commission's enforcement powers are not curtailed by AB 1054 and therefore the Commission may impose penalties on a utility, to be paid by its shareholders, for violations of safety rules and Commission orders.

For all of these reasons the Commission disagrees with the proposition that establishing the Wildfire Fund NBC diminishes incentives for a utility to operate and maintain its system in a manner that mitigates the risk of catastrophic wildfires.

#### **7.4.4. Bill Impacts of the Wildfire Fund NBC**

Several parties correctly point out that the Wildfire Fund NBC creates a bill impact for ratepayers that would not exist absent imposition of the Wildfire Fund NBC.<sup>111</sup> However, the Commission notes that a future catastrophic wildfire in the absence of AB 1054 may have increased ratepayer costs as well.

---

<sup>111</sup> CforAT opening comments at 4; TURN reply comments at 1; Cal Advocates opening comments at 17; EPUC opening comments at 4-6.

CforAT in its comments speaks to the necessity for the Commission to consider the impact on future customer bills if the Wildfire Fund NBC is not approved. It is possible that the future holds more catastrophic wildfires than previously seen, and significant bill impacts for utility ratepayers in the absence of a mechanism to dispose of wildfire claims quickly and keep costs of capital to a reasonable level. Earlier in this decision the Commission described these and other ratepayers benefits attributable to the Wildfire Fund NBC when finding it just and reasonable.

Thus, even though it is evident the Wildfire Fund NBC is an incremental charge compared to the expiration of the DWR Bond Charge and the absence of the Wildfire Fund NBC, it is also true that the Wildfire Fund NBC is designed to collect an equivalent level of revenue as the current DWR Bond Charge, and the Wildfire Fund NBC is reasonable as the benefits for ratepayers of participating utilities outweigh the incremental charge.

#### **7.4.5. Controls on Administrative Costs and Expenses**

Some parties sought to ensure that ratepayers do not pay more than is necessary to support the bonds eventually issued by DWR. In particular, UCAN sought an audit of DWR administrative expenses to ensure that they were reasonable.

Parties are correct that interest rates are a key variable for determining annual payments needed to fund a lump sum contribution to the Wildfire Fund. However, that analysis is not relevant here where the Commission's responsibility is to consider a revenue requirement based on historic collections rather than estimated future costs.

Furthermore, AB 1054's mandate does not allow the Commission to set a revenue requirement other than that defined by Water Code Section 80524. For that reason, even if a given year's financing and administrative costs related to DWR's bond issuance are lower than the annual revenue requirement authorized, there can be no adjustment of the collections for that year. The revenue requirement for the Wildfire Fund NBC would remain the same. This is in contrast to the current DWR Bond Charge methodology which, as noted by CLECA, allows for annual adjustments to the revenue requirement to account for lower or higher expenses.

The unavoidable construction of AB 1054 is that once the revenue requirement is set by this decision it cannot be changed until 2036.<sup>112</sup> The static revenue requirement will be used to issue, service, and administer up to \$10.5 billion of DWR bonds to support the Wildfire Fund.<sup>113</sup> AB 1054 describes several forms of financial and administrative expenses that may be incurred in support of the bond issuance.<sup>114</sup> AB 1054 also dictates that after DWR has satisfied these various purposes, it will transfer any remaining revenue requirement to the Wildfire Fund.<sup>115</sup> Public Utilities Code Sections 3281 – 3288 and 3292(i)(2) specify how the fund will be administered and capitalized, describe legislative reporting requirements, and specify the process for terminating the Wildfire Fund in the event the Wildfire Fund is exhausted. Thus, the Legislature has already determined the use of any collections from ratepayers. While noting parties' concern about this issue, the Legislature

---

<sup>112</sup> Water Code § 80544(b).

<sup>113</sup> Water Code § 80540(b).

<sup>114</sup> Water Code § 80544(a)(1)-(5).

<sup>115</sup> Water Code § 80544(a)(6); Water Code § 80550(b).

considered how to address it in AB 1054 and subsequent legislation in AB 1513 (Ch. 396, Stats. 2019).

## **8. Comments on Proposed Decision**

The proposed decision of Administrative Law Judge (ALJ) Doherty in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on October 14, 2019 by EPUC, TURN (separately and jointly with Joint CCAs), CforAT, Wild Tree Foundation, Joint CCAs, Cal Advocates, PG&E, SCE, SDG&E, Ruth Henricks, William Abrams, and UCAN. Reply comments were filed on October 21, 2019 by TURN, Ruth Henricks, CCUE, CforAT, Wild Tree Foundation, SDG&E, EPUC, PG&E, SCE, SEIA, and UCAN. Changes have been made throughout the decision in response to party comments. Typographical and other non-substantive edits have also been made.

In comments on the proposed decision, TURN requests modifications related to the Wildfire Fund contributions made by electrical corporation shareholders. However, this decision notes that Public Utilities Code Sections 3292(b)(3) and 3292(c) specify that all large electrical corporation contributions to the Wildfire Fund shall not be recovered from the ratepayers of an electrical corporation. Although shareholder contributions are important part of this decision's finding that imposing the Wildfire Fund NBC is reasonable and in the public interest, the accounting for and treatment of shareholder contributions is outside the scope of this proceeding. Alleged impermissible ratepayer subsidization of shareholder contributions or questions about the tax treatment of shareholder contributions should be addressed in other proceedings.

## **9. Assignment of Proceeding**

Clifford Rechtschaffen is the assigned Commissioner and Patrick Doherty is the assigned Administrative Law Judge in this proceeding.

### **Findings of Fact**

1. The regional electrical corporations have notified the Commission that they do not intend to participate in the Wildfire Fund.
2. The existing DWR Bond Charge is collected on a dollar per kWh basis and this charge has averaged approximately half a cent per kWh over the last several years.
3. All customers in all customer classes are required to pay the DWR Bond Charge on an equal cents per kWh basis, with some exceptions.
4. The DWR Bond Charge revenue allocation method assigns the costs of the DWR Bond Charge to each class proportionate to a class's share of the utility's kWh sales in a given year.
5. The DWR Bond Charge is not collected from several types of customers including CARE residential customers, Medical Baseline residential customers, and continuous DA customers.
6. The Legislature has determined that it is in the public interest to establish the Wildfire Fund and create a detailed construct for managing future wildfire claims as defined by AB 1054.
7. The Wildfire Fund is designed to be capitalized with contributions from both ratepayers and shareholders.
8. AB 1054's scheme essentially provides an insurance fund that can protect ratepayers from future recovery in rates for prudently incurred utility wildfire costs for which ratepayers might otherwise be responsible to pay in full.

9. Uncertainty about cost recovery for wildfire liabilities, led to credit rating downgrades for SCE and SDG&E in 2019.

10. Imposing the Wildfire Fund NBC is in the public interest as it supports the framework for managing wildfire risk established by AB 1054.

11. Beyond the credit downgrades experienced by SCE and SDG&E, the utilities faced a threat of continuing downgrades in the future – and attendant increases in ratepayer costs to finance utility investments – absent a solution such as the structure imposed by AB 1054.

12. The credit ratings of SCE and SDG&E were generally stabilized by AB 1054, and all else being equal, the prevention of credit rating downgrades for electrical corporations reduces ratepayer costs.

13. The Wildfire Fund NBC creates a bill impact for ratepayers that would not exist absent imposition of the Wildfire Fund NBC, although it is also true that the Wildfire Fund NBC is designed to collect an equivalent level of revenue as the current DWR Bond Charge.

14. The large electrical corporations have indicated their choice or intention to participate in the Wildfire Insurance Fund.

### **Conclusions of Law**

1. The broad powers granted to the Commission by Public Utilities Code Section 701, and the Legislature's endorsement of the Commission's authority under that statute to impose the Wildfire Fund NBC, grant the Commission jurisdiction and authority to impose the Wildfire Fund NBC.

2. By referring to Public Utilities Code Section 701, Public Utilities Code Section 3289(a)(1) directs the Commission to apply its broadest discretion and authority when determining if it is in the public interest and just and reasonable to impose the Wildfire Fund NBC.

3. Any Wildfire Fund NBC collections from regional electrical corporation ratepayers shall be treated separately from the annual revenue requirement for the Wildfire Fund NBC established in Water Code Section 80524(a) and are not covered by the Rate Agreement between DWR and the Commission.

4. AB 1054 is clear that the annual revenue requirement for the Wildfire Fund NBC must be based on historic collections made by DWR for the DWR Bond Charge.

5. As a matter of law, the ratepayers of an electrical corporation that is not participating in the Wildfire Fund should not pay the Wildfire Fund NBC.

6. In setting a total annual revenue requirement for the Wildfire Fund NBC the Commission must take into account only the large electrical corporations that are eligible and elect to participate in the Wildfire Fund.

7. AB 1054 contains no provision that allows a large electrical corporation to change its status as a participating utility and as a result the commitment to make annual contributions contained in the statute must be implemented as a binding commitment.

8. The Commission's determination that it will exercise its authority to impose the Wildfire Fund NBC on the ratepayers of electrical corporations participating in the Wildfire Fund, and that the imposition of such a charge is just and reasonable, triggers a provision of Water Code Section 80524(b) that requires the Commission to enter into an agreement with DWR with respect to the revenue requirement and the Wildfire Fund NBC that shall have the force and effect of an irrevocable financing order.

9. The Rate Agreement attached to this decision complies with the requirements of Water Code Section 80524(b) and other applicable law.

10. The proposed Rate Agreement as submitted to the parties in the ALJ ruling of August 21, 2019, and as modified to make some technical changes, complies with the requirements of Water Code Section 80524(b) and other applicable law.

11. Rate Agreement Sections 1, 4.1(a) and 4.1(b) provide for the proper administration of the revenue requirement.

12. Rate Agreement Section 4.1, as a whole, provides for notification of the Commission and subsequent action to comply with Water Code Section 80524(b).

13. Rate Agreement Sections 5.1(a) and 5.1(b) contain a rate covenant and Section 5.1(c) states that those sections shall have the force and effect of a financing order.

14. AB 1054 specifies that if the Wildfire Fund NBC is adopted then it should be collected “in the same manner as” the current DWR Bond Charge, and the term “in the same manner” means that the Wildfire Fund NBC should be collected in no different a manner than the DWR Bond Charge.

15. Collecting the Wildfire Fund NBC as a fixed charge (presumably on a dollar per customer/month basis) would not collect the charge in the same manner as the DWR Bond Charge.

16. Maintaining the revenue allocation for the Wildfire Fund NBC so that it is no different than the existing revenue allocation for the DWR Bond Charge is equitable and conforms with the statute’s instructions to collect the Wildfire Fund NBC in the same manner as the DWR Bond Charge.

17. CARE and Medical Baseline residential customers should be excluded from paying the Wildfire Fund NBC.

18. Continuous DA customers should be excluded from paying the Wildfire Fund NBC.

19. Any other customers currently exempted from the DWR Bond Charge, such as certain customers utilizing CGDL as defined by D.03-04-030, should be excluded from paying the Wildfire Fund NBC.

20. The Legislature and the Governor determined that the creation of the Wildfire Fund furthers state policy goals and benefits ratepayers.

21. The imposition of the Wildfire Fund NBC created by AB 1054 is just and reasonable.

22. The shareholder contributions to the Wildfire Fund provide benefits to ratepayers.

23. The directive of Public Utilities Code Section 451.1 that the Commission shall allow cost recovery if a utility's costs and expenses are just and reasonable in a catastrophic wildfire proceeding is satisfied by the payment of costs prudently incurred by the electrical corporation that are paid from the Wildfire Fund.

24. "Cost recovery" as defined by Public Utilities Code Section 451.1 has already occurred when an eligible wildfire claim is paid by the Wildfire Fund.

25. The determination that the Wildfire Fund NBC is just and reasonable is based on several considerations, including the elimination of the potential imposition of double payments by utility ratepayers for the same eligible wildfire claim.

26. AB 1054 does not require ratepayers to reimburse the Wildfire Fund or an electrical corporation for eligible wildfire claims paid by the Wildfire Fund that are later determined to be just and reasonable.

27. Costs and expenses initially paid for by the Wildfire Fund, and that the Commission later deems just and reasonable in a catastrophic wildfire proceeding, are not subject to reimbursement to the Wildfire Fund.

28. Public Utilities Code Section 1701.8 directs a utility that has received payments from the Wildfire Fund for third-party damage claims to file an application pursuant to Public Utilities Code Section 451.1 (for covered wildfires) within specific time periods.

29. Public Utilities Code Section 1701.8 establishes a procedural vehicle for determining whether costs paid from the Wildfire Fund must be paid back to the Wildfire Fund by utility shareholders, up to a certain cap, or are recovered from the Wildfire Fund itself under Public Utilities Code Section 3292.

30. The catastrophic wildfire proceeding, as indicated by the legislatively determined scope, does not itself authorize rate recovery of wildfire costs paid by the Wildfire Fund.

31. The Wildfire Fund NBC authorized by this decision, which will be in an amount sufficient to support the annual revenue requirement established by this decision, constitutes the only payments ratepayers will be required to make for eligible wildfire claims paid from the Wildfire Fund.

32. The Wildfire Fund NBC is reasonable as the benefits for ratepayers of participating utilities outweigh the incremental charge.

33. AB 1054's mandate does not allow the Commission to set a revenue requirement other than that defined by Water Code Section 80524.

34. Pursuant to AB 1054, once the revenue requirement is set by this decision it cannot be changed until 2036.

35. AB 1054 describes several forms of financial and administrative expenses that may be incurred in support of the bond issuance. AB 1054 also dictates that after DWR has satisfied these various purposes, it will transfer any remaining revenue requirement amount left to the Wildfire Fund.

## **O R D E R**

### **IT IS ORDERED** that:

1. Once a large electrical corporation has made its commitment to participate in the Wildfire Fund, then it shall continue to participate in the Wildfire Fund and shall fully satisfy the statutorily required shareholder contributions.

2. Each large electrical corporation that is eligible and elects to participate in the Wildfire Fund shall impose the Wildfire Fund non-bypassable charge in an amount determined necessary to collect the revenue requirement authorized by this decision.

3. The total annual revenue requirement for the Wildfire Fund non-bypassable charge shall be set at the sum, not to exceed \$902,400,000, of the following amounts historically collected from customers of each large electrical corporation that is eligible and elects to participate in the Wildfire Fund: \$404,600,000 for historic collections if Pacific Gas and Electric Company participates in the Wildfire Fund, \$408,200,000 for historic collections if Southern California Edison Company participates in the Wildfire Fund, and \$89,600,000 for historic collections if San Diego Gas & Electric Company participates in the Wildfire Fund.

4. Pursuant to Water Code Section 80524(a), the annual revenue requirement for the Wildfire Fund non-bypassable charge shall remain in effect until January 1, 2036.

5. The Wildfire Fund non-bypassable charge shall be collected by the large electrical corporations on a dollar per kilowatt-hour basis to conform with the directive of Public Utilities Code Section 3289(a)(2).

6. The Wildfire Fund non-bypassable charge shall use the same revenue allocation as the Department of Water Resources Bond Charge.

7. All customers of a large electrical corporation that is eligible and elects to participate in the Wildfire Fund shall pay the same amount per kilowatt-hour for the Wildfire Fund non-bypassable charge, unless that customer is excluded from paying the Wildfire Fund non-bypassable charge.

8. The Wildfire Fund non-bypassable charge shall not be collected from customers of large electrical corporations that are California Alternate Rates for Energy residential customers.

9. The Wildfire Fund non-bypassable charge shall not be collected from customers of large electrical corporations that are Medical Baseline residential customers.

10. Customers that have been taking direct access service continuously both before and since January 17, 2001 in the Pacific Gas and Electric Company and Southern California Edison Company service territories shall not pay the Wildfire Fund non-bypassable charge.

11. Customers that have been taking direct access service continuously both before and since February 7, 2001 in San Diego Gas & Electric Company's service territory shall not pay the Wildfire Fund non-bypassable charge.

12. Customers utilizing customer generation departing load that are currently exempted from paying the Department of Water Resources Bond Charge per Decision 03-04-030 shall not pay the Wildfire Fund non-bypassable charge.

13. Any customers currently exempted from paying the Department of Water Resources Bond Charge shall not pay the Wildfire Fund non-bypassable charge.

14. For any regional electrical corporation that voluntarily imposes a Wildfire Fund non-bypassable charge on its customers, that Wildfire Fund non-bypassable charge shall be one-half cent per kilowatt-hour.

15. If a regional electrical corporation elects to participate in the Wildfire Fund and impose the Wildfire Fund non-bypassable charge (NBC) on its customers, the same Wildfire Fund NBC exclusions as apply to large electrical corporation customers shall apply to the regional electrical corporation's customers.

16. The Rate Agreement between the Department of Water Resources and the California Public Utilities Commission contained in Attachment A of this decision is adopted by the Commission pursuant to Water Code Section 80524(b).

17. The Executive Director of the California Public Utilities Commission shall sign the Rate Agreement on behalf of the Commission. Once the Department of Water Resources has signed the Rate Agreement, the Department of Water Resources may serve a copy of the executed Rate Agreement on the service list of this proceeding. The Commission's General Counsel shall retain the Commission's copies of the original executed Rate Agreement.

18. Once all parties to the Rate Agreement have signed the Rate Agreement, Sections 5.1(a) and 5.1(b) of the Rate Agreement, and only those Sections, shall have the force and effect of an irrevocable financing order issued by the Commission pursuant to Public Utilities Code Section 840 et seq.

19. The instant proceeding remains open in order to consider the annual revenue requirement and sales forecast for the Wildfire Fund non-bypassable charge in 2020.

20. An electrical corporation shall not recover from ratepayers amounts that were already recovered by the electrical corporation from the Wildfire Fund.

21. Rulemaking 19-07-017 remains open.

This order is effective today.

Dated October 24, 2019, at Redding, California.

MARYBEL BATJER

President

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

GENEVIEVE SHIROMA

Commissioners

# **ATTACHMENT A**

**~~PROPOSED~~ RATE AGREEMENT**

**By and Between**

**STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES**

**and**

**STATE OF CALIFORNIA PUBLIC UTILITIES COMMISSION**

**Dated as of ~~October~~ \_\_\_\_\_, 2019**

## TABLE OF CONTENTS

|                                                                                | <u>Page</u> |
|--------------------------------------------------------------------------------|-------------|
| ARTICLE I DEFINITIONS .....                                                    | 1           |
| Section 1.1    Definitions .....                                               | 1           |
| ARTICLE II REPRESENTATIONS AND WARRANTIES .....                                | 3           |
| Section 2.1    Representations and Warranties of Department .....              | 3           |
| Section 2.2    Representations and Warranties of Commission .....              | 3           |
| ARTICLE III PURPOSES OF THE AGREEMENT .....                                    | 4           |
| Section 3.1    Funding of the Wildfire Fund; Agreement for Bond Issuance ..... | 4           |
| Section 3.2    No Indebtedness .....                                           | 4           |
| Section 3.3    No Pecuniary Liability of Commission .....                      | 4           |
| ARTICLE IV REVENUE REQUIREMENTS .....                                          | 4           |
| Section 4.1    Revenue Requirements .....                                      | 4           |
| ARTICLE V CHARGE COVENANT .....                                                | 6           |
| Section 5.1    Charge Covenant .....                                           | 6           |
| ARTICLE VI COVENANTS OF THE COMMISSION .....                                   | 6           |
| Section 6.1    Compliance with Agreement .....                                 | 6           |
| Section 6.2    Liens .....                                                     | 7           |
| ARTICLE VII COVENANTS OF THE DEPARTMENT .....                                  | 7           |
| Section 7.1    Deposit and Allocation of Revenues. ....                        | 7           |
| Section 7.2    Department Participation. ....                                  | 7           |
| Section 7.3    Compliance with Agreement .....                                 | 7           |
| Section 7.4    Charges .....                                                   | 8           |

|                                                   |                                 |    |
|---------------------------------------------------|---------------------------------|----|
| Section 7.5                                       | Department Audits .....         | 8  |
| ARTICLE VIII EVENTS OF DEFAULT AND REMEDIES ..... |                                 | 8  |
| Section 8.1                                       | Events of Default .....         | 8  |
| Section 8.2                                       | Remedies .....                  | 8  |
| Section 8.3                                       | Consent to Assignment .....     | 8  |
| ARTICLE IX TERMINATION .....                      |                                 | 9  |
| Section 9.1                                       | Termination .....               | 9  |
| ARTICLE X AMENDMENTS .....                        |                                 | 9  |
| Section 10.1                                      | Amendments to Agreement .....   | 9  |
| ARTICLE XI MISCELLANEOUS .....                    |                                 | 9  |
| Section 11.1                                      | No Waiver .....                 | 9  |
| Section 11.2                                      | Notices .....                   | 9  |
| Section 11.3                                      | Severability .....              | 9  |
| Section 11.4                                      | Headings .....                  | 10 |
| Section 11.5                                      | Governing Law .....             | 10 |
| Section 11.6                                      | Counterparts .....              | 10 |
| Section 11.7                                      | Date of Agreement .....         | 10 |
| Section 11.8                                      | Third Party Beneficiaries ..... | 10 |
| Section 11.9                                      | No Implied Waivers .....        | 10 |
| Section 11.10                                     | No Assignment .....             | 10 |

**RATE AGREEMENT**, dated as of ~~October~~ \_\_\_\_\_, 2019, by and between  
**STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES** and **STATE OF CALIFORNIA PUBLIC UTILITIES COMMISSION**.

The parties mutually agree as follows:

**ARTICLE I**  
**DEFINITIONS**

Section 1.1 **Definitions.** The terms set forth in this Section shall have the meanings ascribed to them herein for all purposes of this Agreement unless the context clearly requires otherwise. Words in the singular shall include the plural and words in the plural shall include the singular where the context so requires.

**“Act”** shall mean The Wildfire Prevention and Recovery Act of 2019 as amended from time to time.

**“Agreement”** shall mean this Rate Agreement, as from time to time hereafter amended or supplemented in accordance with the provisions hereof.

**“Bonds”** shall mean bonds, notes or other evidences of indebtedness issued or incurred pursuant to Section 80540 of the Water Code, including, refunding bonds issued in accordance with Section 80540 of the Water Code.

**“Bond Related Parties”** shall mean (i) the Department, its agents, officers, employees or consultants, (ii) owners or beneficial owners of the Bonds, (iii) any Fiduciary, (iv) any municipal bond insurance company, bank or other financial institution or organization, including their participants, that (A) provides credit support or liquidity for some or all of the Bonds, including but not limited to, pursuant to letters of credit, bond insurance, guarantees, debt service reserve fund surety bonds, lines of credit, revolving credit agreement, reimbursement agreements, and standby bond purchase agreements, (B) provides other financial instruments entered into in connection with the Bonds, including but not limited to, pursuant to investment agreements, hedges, interest rate swaps, caps, options and forward purchase agreements, (C) provides services relating to the remarketing of the Bonds, including but not limited to, pursuant to remarketing agreements, dealer agreements and auction agent agreements, or (D) any other person having a lien on or security interest in bond proceeds or revenues received by the Department for deposit in the Department of Water Resources Charge Fund as consideration for providing financial products or services in connection with the Bonds, and (v) any collateral, paying, or other agent with respect to the Bonds.

**“Charge Fund”** shall mean the Department of Water Resources Charge Fund established by the Act.

**“Commission”** shall mean the State of California Public Utilities Commission and any board, commission, department, corporation, authority or officer succeeding to the functions thereof, or to whom the powers conferred on the Commission by the Act shall be given by law.

**“Department”** shall mean the State of California Department of Water Resources.

**“DWR Bond Charges”** shall mean collected charges imposed pursuant to the bond related revenue requirements established by the Department under Section 80110 of Division 27 for the period from January 1, 2013, through December 31, 2018 at the rates adopted by the Commission and allocated to the electric customers of PG&E, SCE, and SDG&E.

**“Electrical Corporation”** shall have the meaning ascribed thereto in Section 218 of the Public Utilities Code, including any successor and assign thereof.

**“Fiduciary”** shall mean any Trustee, any bond registrar and any paying agent in connection with Bonds pursuant to the Financing Documents, and their respective successors and assigns.

**“Financing Documents”** shall mean any resolution, indenture, trust agreement, loan agreement, revolving credit agreement, reimbursement agreement, standby purchase agreement or other agreement or instrument adopted or entered into by the Department authorizing, securing, enhancing, or hedging the Bonds, including any bond offering documents, as from time to time amended or supplemented in accordance therewith. Copies of all Financing Documents shall be provided to the Commission.

**“Large Electrical Corporation”** shall mean an electrical corporation with 250,000 or more customer accounts within the State that has met the requirements of Sections 3292(a) and 3292(b)(1) or Section 3292(d) of the Public Utilities Code.

**“Nonbypassable Charges”** shall mean a charge imposed by the Commission, by order in conjunction with this Agreement, upon customers in each of the Service Areas of any Large Electrical Corporation that is eligible and elects to participate in the Wildfire Fund or any of their respective successors, such charge to be revised from time to time by the Commission in accordance with Section 80524(b) of the Water Code and Section 3289 of the Public Utilities Code; provided that the Nonbypassable Charges shall be imposed upon such customers in each Service Area at all times required by this Agreement, the Commission and the Act.

**“Program Related Costs”** shall mean the following payments of, or deposits or other provision to be made by, the Department under Financing Documents or the Act in accordance with Section 80524(a) and 80544 of the Water Code:

- (i) the amounts necessary to pay the principal of, and premium, if any, and interest on, all Bonds as and when the Bonds shall become due,
- (ii) the amounts necessary to make payments under any contracts, agreements, or obligations entered into by the Department pursuant to the Act, in the amounts and at the times they shall become due,
- (iii) reserves in such amount as may be determined by the Department from time to time to be necessary or desirable,

(iv) consistent with Section 3288 of the Public Utilities Code, repayment of loans made from the Surplus Money Investment Fund to the Wildfire Fund, and

(v) the administrative costs of the Department incurred in administering Division 28 of the Water Code.

**“Revenue Requirement”** shall mean the revenue requirement for each year or, with respect to the first year and last year, the pro rata portion of the year, as set forth in Section 80524(a) of the Water Code and calculated as agreed and set forth in Article IV.

**“Revenue Requirement Period”** means each annual period from January 1 through December 31 until January 1, 2036.

**“Service Area”** shall mean the geographic area in which an Electrical Corporation distributes electricity.

**“State”** shall mean the State of California.

**“Trustee”** shall mean any bank or trust company, or the State Treasurer, appointed as trustee, co-trustee or collateral agent in connection with the Bonds or bond related obligations pursuant to the Financing Documents, and its successors and assigns.

**“Wildfire Fund”** shall mean the fund created pursuant to Section 3284 of the Public Utilities Code.

## **ARTICLE II REPRESENTATIONS AND WARRANTIES**

Section 2.1 Representations and Warranties of Department. The Department makes the following representations and warranties as the basis for the undertakings on its part herein contained:

(a) It is a department within the Resources Agency of the State, validly existing under the Constitution and laws of the State, and has full power and authority to execute, deliver and perform and observe all of the terms and provisions of this Agreement.

(b) The execution, delivery and performance of this Agreement have been duly authorized by all necessary action on the part of the Department.

(c) This Agreement is a legal, valid and binding agreement of the Department and is enforceable against the Department in accordance with its terms.

Section 2.2 Representations and Warranties of Commission. The Commission makes the following representations and warranties as the basis for the undertakings on its part herein contained:

(a) It is a commission of the State, validly existing under the Constitution and laws of the State, and has full power and authority to execute, deliver and perform and observe all of the terms and provisions of this Agreement.

(b) The execution, delivery and performance of this Agreement, have been duly authorized by all necessary action on the part of the Commission.

(c) This Agreement is a legal, valid and binding agreement of the Commission and is enforceable against the Commission in accordance with its terms.

### **ARTICLE III PURPOSES OF THE AGREEMENT**

Section 3.1 Funding of the Wildfire Fund; Agreement for Bond Issuance. The Department and the Commission agree that this Agreement is executed to facilitate the funding of the Wildfire Fund. The Department and the Commission further agree that, to the extent the Department issues Bonds, this Agreement is executed to facilitate the issuance of Bonds.

Section 3.2 No Indebtedness. Nothing contained in the Agreement shall be deemed to create or constitute a debt or liability of the State or of any political subdivision thereof, or a pledge of the full faith and credit or taxing power of the State or of any such political subdivision.

Section 3.3 No Pecuniary Liability of Commission. Nothing in this Agreement shall be deemed to create any pecuniary liability of the Commission, its Commissioners, employees or agents to any person, the sole remedy for any default, breach or other nonperformance by the Commission hereunder being the exercise of remedies specifically afforded hereunder and under the Act.

### **ARTICLE IV REVENUE REQUIREMENTS**

Section 4.1 Revenue Requirements.

(a) Determination of Revenue Requirement. The Department agrees to cooperate with and assist the Commission in its determination of the Revenue Requirement established by Section 80524 of the Water Code. The Commission agrees to adopt the Revenue Requirement which shall remain in effect until January 1, 2036. The Department and the Commission agree that the annual Revenue Requirement shall be equal to the average annual amount of collections by the Department with respect to the DWR Bond Charges imposed for the period from January 1, 2013 through December 31, 2018 on customers of each Large Electrical Corporation that is eligible and elects to participate in the Wildfire Fund.

(b) Determination of Nonbypassable Charges. The Department agrees to cooperate with and assist the Commission in its determination, at least annually, of the Nonbypassable Charges. Pursuant to Section 3289 of the Public Utilities Code, the Commission

shall impose the Nonbypassable Charges in an amount sufficient to fund the Revenue Requirement.

(c) Review of Sufficiency. The Department shall, at least annually, and more frequently as deemed reasonably necessary or appropriate by the Department or the Commission, conduct a review and determine if the amount collected by the Nonbypassable Charges is forecasted to be sufficient to meet the Revenue Requirement. If any such annual or more frequent review indicates that collections received by the Department with respect to the Revenue Requirement are, or will be, insufficient to meet the Revenue Requirement, and the Department so notifies the Commission, the Commission shall take necessary action to cure or avoid any such deficiency, including adjustment of existing, and the calculation and imposition of additional, Nonbypassable Charges. To the extent that the Department has not provided a notice to the Commission of any deficiency within the time periods required by the next succeeding paragraph for any reason and the Commission determines based on the record before it, that Nonbypassable Charges are not sufficient to meet the Revenue Requirement, the Commission may modify the Nonbypassable Charges to cover such shortfall on an interim basis pending receipt of a notice of a deficiency from the Department.

The Department shall notify the Commission each year by November 1st of the annual collections received by the Department with respect to the Revenue Requirement and the amount of excess or deficiency in collections above or below the Revenue Requirement and the Commission will undertake within 60 days to adjust the Nonbypassable Charges in the subsequent year to reflect any excess or deficiency.

Within any Revenue Requirement Period if the Department forecasts that the Revenue Requirement will not be met and that the collections will not be sufficient to fund the Revenue Requirement, then the Department shall notify the Commission in writing within 20 days of such determination, and the Commission shall act within 30 days of such notification to increase the Nonbypassable Charges so that amounts collected during that period are sufficient to fund the Revenue Requirement.

(d) Information. In any review of the adequacy of the Nonbypassable Charges, the Department shall include the amount required to be recovered in the applicable period and shall set forth amounts projected to be required to be collected during subsequent periods. The review of the adequacy of the Nonbypassable Charges in any period shall take into account any deficiency or any surplus in amounts recovered in earlier periods. The Department's at least-yearly notification to the Commission of the amounts needed to be collected from the Nonbypassable Charges shall include a statement containing the Department's projections (with reasonable detail) of the following information for each month during the period covered by the Revenue Requirement:

(i) the beginning balance of funds on deposit in the Charge Fund, including the amounts on deposit in each account and subaccount of the Charge Fund;

(ii) the amounts necessary to pay or provide for the payment of all Program Related Costs as and when the same shall become due and the amount of Nonbypassable Charges to be collected for such purpose; and

(iii) any other information reasonably requested by the Commission in its proceedings implementing a Revenue Requirement.

## **ARTICLE V CHARGE COVENANT**

### **Section 5.1    Charge Covenant.**

(a) The Commission hereby covenants and agrees to calculate, revise and impose from time to time, Nonbypassable Charges sufficient to provide moneys so that the amounts available for deposit in the Charge Fund from time to time are at all times sufficient to fund the Revenue Requirement.

(b) As provided by and authorized by the Act, including by reference to Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the California Public Utilities Code, the Nonbypassable Charges authorized by Commission Order and the right of the Department to receive the Nonbypassable Charges as provided in this Agreement shall be property of the Department for all purposes under California law. After the transfer of moneys by the Department to, and deposited in, the Wildfire Fund in accordance with the Act such moneys are not property of the Department following such transfer and deposit, nor shall the Department have any residual interest in any money or investments in the Wildfire Fund.

(c) As authorized by Section 80524(b) of the Water Code by reference to Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the California Public Utilities Code, Sections 5.1(a) and 5.1(b) of this Agreement shall have the force and effect of a “irrevocable financing order” adopted thereunder and shall be enforceable in accordance with the terms hereof, including, without limitation, in circumstances in which the Department has breached its obligations under this Agreement or in respect of the Financing Documents.

## **ARTICLE VI COVENANTS OF THE COMMISSION**

### **Section 6.1    Compliance with Agreement.**

(a) The Commission hereby covenants with the Department that the Commission shall take all such actions or refrain from taking all such actions, as the case may be, so as to comply with the terms and provisions of the Act and this Agreement.

(b) The Commission hereby covenants that, so long as any Bonds shall be outstanding, it will not take any action, or fail to take any action, which, if taken or not taken, as the case may be, would adversely affect the tax-exempt status of the interest payable on Bonds then outstanding, the interest on which, at the time of issuance thereof, was exempt from federal

income taxation or not includable in gross income for purposes of federal income taxation. In furtherance of the foregoing, the Commission agrees to act with respect to those matters within its control that could adversely affect the exclusion of interest on such tax-exempt Bonds from gross income for purposes of federal income taxation.

(c) The Nonbypassable Charges shall be established by the Commission without regard to the levels or amounts of any particular rates or charges authorized by the Commission to be charged by any Electrical Corporation for electrical power sold by such Electrical Corporation.

Section 6.2 Liens. Until all Nonbypassable Charges have been collected in full in accordance with Section 3289 of the Public Utilities Code, the Commission, to the extent it has the power to do so, shall not permit to be created any purported lien upon or pledge of the Nonbypassable Charges except any lien and pledge thereon created by or pursuant to the Act as security for the enforcement of the Department's obligations entered into pursuant thereto.

## **ARTICLE VII COVENANTS OF THE DEPARTMENT**

Section 7.1 Deposit and Allocation of Revenues. The Department hereby covenants and agrees that all revenues received by the Department from the Nonbypassable Charges shall be deposited in the Charge Fund and allocated in accordance with Section 80544(a) of the Water Code. Without limiting the generality of the foregoing, the Department further covenants and agrees that, in accordance with Section 80544(a) of the Water Code, that the Department will, after meeting the purposes of paragraphs (1) to (5), inclusive, of such Section 80544(a), allocate or cause to be allocated any remaining Revenue Requirement amount to the transfer to the Wildfire Fund.

Section 7.2 Department Participation. Consistent with the limitations set forth in Division 28 of the Water Code, upon the request of the Commission, the Department will participate in any Commission proceedings, including providing witnesses, attending public hearings and providing any other materials necessary to facilitate the Commission's completion of its proceedings, taken in connection with the establishment of the Nonbypassable Charges by the Commission.

### Section 7.3 Compliance with Agreement.

(a) The Department hereby covenants with the Commission that the Department shall take all such actions or refrain from taking all such actions, as the case may be, so as to comply with the terms and provisions of the Act and this Agreement, including but not limited to, complying with the legal requirements referenced in Article IV and the requirement to review the sufficiency of Nonbypassable Charges to meet the Revenue Requirement at least annually.

(b) The Department hereby covenants that, so long as any Bonds shall be outstanding, it will not take any action, or fail to take any action, which, if taken or not taken, as the case may be, would adversely affect the tax-exempt status of the interest payable on Bonds then outstanding, the interest on which, at the time of issuance thereof, was exempt from Federal

income taxation or not includable in gross income for purposes of federal income taxation. In furtherance of the foregoing, the Department agrees to act with respect to those matters within its control that could adversely affect the exclusion of interest on such tax-exempt Bonds from gross income for purposes of federal income taxation.

Section 7.4 Charges. The Department acknowledges the Commission's exclusive authority to set the Nonbypassable Charges among customer classes and for each Large Electrical Corporation that is eligible and elects to participate in the Wildfire Fund and to determine the extent or timing of Nonbypassable Charges that may be required in the future, consistent with the Commission's obligations in this Rate Agreement and the Act.

Section 7.5 Department Audits. The Department shall provide to the Commission when available a copy of each audited annual financial statements for the Charge Fund.

## **ARTICLE VIII EVENTS OF DEFAULT AND REMEDIES**

Section 8.1 Events of Default. An "event of default" or a "default" shall mean, whenever they are used in this Agreement, a failure of the Commission to calculate and impose Nonbypassable Charges in accordance with Article V.

Section 8.2 Remedies.

(a) Whenever any event of default shall have occurred and be continuing, and written notice of the default shall have been given to the Commission by the Department and the default shall not have been cured within 30 days, the Department may take whatever action at law or in equity may appear necessary or desirable to enforce performance and observance of any obligation, agreement or covenant of the Commission under Article V.

(b) Whenever any event shall have occurred and be continuing, such that either the Commission or the Department is not in compliance with any covenant or obligation of this Agreement, and written notice of the breach of such covenant or obligation shall have been given to either the Commission or the Department by the other party and the breach shall not have been cured within 30 days, both the Commission or the Department may take whatever action at law or in equity that may appear necessary or desirable to enforce performance and observance of any obligation, agreement or covenant under this Agreement. In addition, whenever any such event shall have occurred and be continuing such that either the Commission or the Department is not in compliance with any covenant or obligation of this Agreement, and the California Catastrophe Response Council provides notice of such breach to the Commission or the Department and the breach shall not have been cured within 120 days, the California Catastrophe Response Council may take whatever action at law or in equity that may appear necessary or desirable to enforce performance and observance of any obligation, agreement or covenant under this Agreement and to such extent the California Catastrophe Response Council shall be considered a third party beneficiary of this Agreement.

**Section 8.3     Consent to Assignment.**

(a)     The Commission consents to the collateral assignment by the Department to the Trustee for the benefit of the Bond Related Parties, as such, of the covenants of the Commission contained in Article V; provided, however, that any rights so granted to the Trustee shall not be greater than the rights of the Department under such Sections of this Agreement, and such right on the part of the Trustee to enforce such covenants shall only commence after the Department has both defaulted under its obligations contained in the Financing Documents and has failed to enforce such covenants in accordance with the terms of this Agreement. Prior to exercising any rights granted to the Trustee in accordance with this Section 8.3, the Trustee shall be required to (i) give prior written notice within the time period required in Section 8.3(b) below, (ii) certify to the Commission that an event of default, other than an event of default predicated solely on the Commission's failure to act hereunder, has occurred under the Financing Documents and (iii) comply or cause the Department to comply with the provisions of this Agreement relating to the Department's rights, duties and obligations hereunder.

(b)     In addition to the requirements of Section 8.3(a) for exercising its rights hereunder, the Trustee shall give the Commission 30 days prior written notice of the exercise by the Trustee of any of the Department's rights under Section 5.1.

**ARTICLE IX  
TERMINATION**

Section 9.1     Termination. The Agreement shall terminate, and the covenants and other obligations contained in the Agreement shall be discharged and satisfied, when (i) all Nonbypassable Charges have been collected, or (ii) January 1, 2036, whichever is later.

**ARTICLE X  
AMENDMENTS**

Section 10.1     Amendments to Agreement. No amendment to the Agreement shall be effective unless it is in writing and signed by each of the parties hereto, provided, however, on or after the issuance of the Bonds, Sections 5.1(a) and (b) may not be amended.

**ARTICLE XI  
MISCELLANEOUS**

Section 11.1     No Waiver. No failure to exercise, and no delay in exercising by the parties hereto, any right, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise of any right, power or privilege hereunder preclude any other or further exercise thereof, or the exercise of any right, power or privilege. The rights and remedies herein provided are cumulative and not exclusive of any rights or remedies provided by law, including the Act.

Section 11.2     Notices. All notices, requests and other communications under this Agreement shall be deemed to have been duly given if in writing and delivered personally or by certified mail (a) to the Department at 1416 9<sup>th</sup> Street, 11<sup>th</sup> Floor, Sacramento, California

95814, attention: Director; (b) to the Commission at 505 Van Ness Avenue, San Francisco, California 94102, attention: Executive Director and General Counsel; or such other address as the Department, or the Commission, as the case may be, shall hereafter designate by notice in writing to the other party.

Section 11.3 Severability. In the event that any one or more of the provisions contained in the Agreement is or are invalid, irregular or unenforceable in any respect, the validity, regularity and enforceability of the remaining provisions contained in this Agreement shall be in no way affected, prejudiced or disturbed thereby.

Section 11.4 Headings. The descriptive headings of the several articles of the Agreement are inserted in the Agreement for convenience only and shall not be deemed to affect the meaning or construction of any of the provisions of the Agreement.

Section 11.5 Governing Law. The Agreement shall be governed by, and construed in accordance with, the Constitution and laws of the State of California, without regard to the provisions thereof regarding conflicts of law.

Section 11.6 Counterparts. This Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

Section 11.7 Date of Agreement. The date of this Agreement shall be for identification purposes only. This Agreement shall become effective immediately upon execution and delivery by the parties hereto.

Section 11.8 Third Party Beneficiaries. Nothing in this agreement express or implied shall be construed to give any person or entity, other than the parties hereto, the California Catastrophe Response Council and the Bond Related Parties, any legal or equitable right, remedy, or claim under or in respect of the agreement or any covenants, agreements, representations, or provisions contained herein.

Section 11.9 No Implied Waivers. Nothing in this Agreement shall be construed to limit the rights of the Commission or the Department to assert any rights it may have with respect to any contract entered into by the Department with respect to its obligations under the Act, or to contest in any proceeding the legality or effect of any contract entered into by the Department with respect to its obligations under the Act.

Section 11.10 No Assignment. Except as set forth in Section 8.3, neither the Department nor the Commission shall assign any of its rights or delegate any of its duties under this Agreement without the express written consent of the other party hereto, provided, however, if, with respect to either party, another governmental entity is created or designated by law to carry out the rights, powers, duties and obligations of such party, then such party may, if required by such law, transfer and assign its right, title and interest in this Agreement to such successor, provided, that such successor entity is permitted by law to assume such party's obligations under this Agreement and agrees in writing to be bound by the terms of this Agreement.

IN WITNESS WHEREOF, the Department has caused this Agreement to be executed in its name by the Director of Water Resources and the Commission ~~by the affirmative vote of the Commission (Decision No. \_\_\_\_\_)~~ has caused this Agreement to be executed in its name by the Executive Director pursuant to the vote of those Commissioners who constituted a majority of the Commission when it approved this agreement, all as of the date first above written.

**STATE OF CALIFORNIA  
DEPARTMENT OF  
WATER RESOURCES**

By:  
Director of Water Resources

**STATE OF CALIFORNIA PUBLIC  
UTILITIES COMMISSION**

By:  
Executive Director

| <b>Summary report:</b><br><b>Litera® Change-Pro for Word 10.7.0.7 Document comparison done on</b><br><b>9/23/2019 2:01:50 PM</b> |   |
|----------------------------------------------------------------------------------------------------------------------------------|---|
| <b>Style name:</b> PW Basic                                                                                                      |   |
| <b>Intelligent Table Comparison:</b> Active                                                                                      |   |
| <b>Original DMS:</b> iw://US/US1/13089019/3                                                                                      |   |
| <b>Modified DMS:</b> iw://US/US1/13089019/4                                                                                      |   |
| <b>Changes:</b>                                                                                                                  |   |
| <u>Add</u>                                                                                                                       | 4 |
| <del>Delete</del>                                                                                                                | 5 |
| <del>Move From</del>                                                                                                             | 0 |
| <u>Move To</u>                                                                                                                   | 0 |
| <u>Table Insert</u>                                                                                                              | 0 |
| <del>Table Delete</del>                                                                                                          | 0 |
| <u>Table moves to</u>                                                                                                            | 0 |
| <del>Table moves from</del>                                                                                                      | 0 |
| Embedded Graphics (Visio, ChemDraw, Images etc.)                                                                                 | 0 |
| Embedded Excel                                                                                                                   | 0 |
| Format changes                                                                                                                   | 0 |
| <b>Total Changes:</b>                                                                                                            | 9 |

(End of Attachment A)

# Attachment B

## **Relevant California Public Utilities Code (PUC) Sections:**

### **PUC Sec. 451.1 (b):**

When determining an application by an electrical corporation to recover costs and expenses arising from a covered wildfire, the commission shall allow cost recovery if the costs and expenses are just and reasonable. Costs and expenses arising from a covered wildfire are just and reasonable if the conduct of the electrical corporation related to the ignition was consistent with actions that a reasonable utility would have undertaken in good faith under similar circumstances, at the relevant point in time, and based on the information available to the electrical corporation at the relevant point in time. Reasonable conduct is not limited to the optimum practice, method, or act to the exclusion of others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with utility system needs, the interest of the ratepayers, and the requirements of governmental agencies of competent jurisdiction. Costs and expenses in the application may be allocated for cost recovery in full or in part taking into account factors both within and beyond the utility's control that may have exacerbated the costs and expenses, including humidity, temperature, and winds.

### **PUC Sec. 701:**

The Commission may supervise and regulate every public utility in the State and may do all the things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction.

### **PUC Sec. 1701.8(b):**

The following procedures and standards apply to a catastrophic wildfire proceeding:

(1) (A) An electrical corporation may file an application pursuant to Section 451 or 451.1, as applicable, at any time after it has paid, or entered into binding commitments to pay, all or, if authorized by the commission for good cause, substantially all third-party damage claims, including payments made pursuant to judgments or settlement agreements related to a covered wildfire. Except as authorized by the commission for good cause, before filing the application, the

electrical corporation shall exhaust all rights to indemnification or other claims, contractual or otherwise, against any third parties, including collecting insurance proceeds, related to the covered wildfire.

(B) If an electrical corporation has received payments from the Wildfire Fund for a third-party damage claim for the covered wildfire, the electrical corporation shall file an application to recover the costs pursuant to subparagraph (A) no later than the earlier of the following:

(i) The date when it has resolved all third-party damage claims and exhausted all right to indemnification or other claims, contractual or otherwise, against any third parties, including collecting insurance proceeds, related to the covered wildfire.

(ii) The date that is 45 days after the date the administrator requests the electrical corporation to make such an application.

(2) The president of the commission, upon the initiation of a catastrophic wildfire proceeding by the filing of an application pursuant to paragraph (1), shall assign a commissioner to act as the presiding officer in the proceeding and an administrative law judge to assist in conducting the proceeding.

(3) Within 15 days of the filing date of the application, the commission shall notice a prehearing conference, which shall be held within 25 days of the filing date.

(4) (A) Within 30 days of the filing date of the application, the assigned commissioner shall prepare and issue, by order or ruling, a scoping memorandum that states that the scope of the proceeding shall be whether the electrical corporation's costs and expenses for the covered wildfire are just and reasonable pursuant to Section 451 or 451.1, as applicable.

(B) The scoping memorandum shall establish a schedule for the proceeding, including the date of issuance of a proposed decision that is no later than 12 months after the filing date of the application.

(C) The assigned commissioner may extend the time established in the scoping memorandum for the date of issuance of a proposed decision by up to six months upon a showing of good cause.

(5) Notwithstanding any other law, the commission may meet in closed session at any point during the pendency of the catastrophic wildfire proceeding with a

three-day notice to the public if the commission establishes a quiet period pursuant to paragraph (6) of subdivision (h) of Section 1701.3.

**PUC Sec. 3289:**

3289. (a) (1) No later than July 26, 2019, the commission shall initiate a rulemaking proceeding to consider using its authority pursuant to Section 701 to require each electrical corporation, except a regional electrical corporation that chooses not to participate in any fund pursuant to Chapter 3 (commencing with Section 3291), to collect a nonbypassable charge from ratepayers of the electrical corporation to support the fund, including the payment of any bonds issued pursuant to Division 28 (commencing with Section 80500) of the Water Code, as follows:

(A) For a large electrical corporation, a charge in an amount sufficient to fund the revenue requirement, as established pursuant to Section 80524 of the Water Code.

(B) For a regional electrical corporation, the amount equal to one-half cent per kilowatt-hour (\$0.005/kWh).

(2) If the commission determines that the imposition of the charge described in paragraph (1) is just and reasonable, and that it is appropriate to exercise its authority pursuant to Section 701 to do so, the commission shall direct each electrical corporation to impose and collect that charge commencing in the month immediately following the month in which the final imposition of the revenue requirement with respect to bonds previously issued pursuant to Division 27 (commencing with Section 80000) of the Water Code is made. The charge shall be collected in the same manner as that for the payments made to reimburse the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code.

(b) Notwithstanding any other law, no later than 90 days after the initiation of the rulemaking proceeding, the commission shall adopt a decision regarding the imposition of the charge.

(c) Notwithstanding Section 455.5 or 1708, or any other law, the commission shall not revise, amend, or otherwise modify a decision to impose a charge made pursuant to this section at any time prior to January 1, 2036.

**PUC Sec. 3292(b)(2):**

For a regional electrical corporation, it has voluntarily established a charge required by the commission pursuant to Section 3289. This charge shall be included on monthly bills for customers. Collections on that charge shall be remitted, on a monthly basis, to the administrator for deposit into the fund.

**PUC Sec. 3292(h):**

(1) Except as provided in paragraph (2), within six months after the commission adopts a decision in an application filed pursuant to Section 1701.8, the electrical corporation shall reimburse the fund for the full amount of costs and expenses the commission determined were disallowed pursuant to Section 1701.8.

(2) (A) The obligation of an electrical corporation to reimburse the fund shall be the lesser amount of subparagraph (B) or (C).

(B) The costs and expenses disallowed pursuant to Section 1701.8.

(C) The amount determined pursuant to clause (i) minus the amount determined pursuant to clause (ii).

(i) Twenty percent of the electrical corporation's total transmission and distribution equity rate base, including, but not limited to, its Federal Energy Regulatory Commission (FERC) assets, as determined by the administrator for the calendar year in which the disallowance occurred.

(ii) The sum of (I) the amounts actually reimbursed to the fund for costs and expenses that were disallowed pursuant to Section 1701.8 during the measurement period, added to (II) the amount of any reimbursements to the fund owed by the electrical corporation for costs and expenses disallowed during the measurement period that have not yet been paid.

(iii) For purposes of this subparagraph, "measurement period" means the period of three consecutive calendar years ending on December 31 of the year in which the calculation is being performed.

(D) The administrator shall publish calculations of the amounts determined pursuant to subparagraphs (B) and (C) on or before January 1 of each calendar year for each electrical corporation.

(E) Except as provided in paragraph (3), the electrical corporation shall not be required to reimburse the fund for any additional amounts in any three-calendar-year period.

(F) The limitation set forth in this section shall apply only so long as the fund has not been terminated pursuant to subdivision (i).

(3) Paragraph (2) does not apply under either of the following circumstances:

(A) If the administrator determines that the electrical corporation's actions or inactions that resulted in the covered wildfire constituted conscious or willful disregard of the rights and safety of others.

(B) If the electrical corporation fails to maintain a valid safety certification on the date of the ignition

## **Relevant Water Code Sections:**

### **Water Code Sec. 80524(a):**

The revenue requirement for each year or, with respect to the first year and last year, the pro rata portion of the year, shall be equal to the average annual amount of collections by the department with respect to charges imposed pursuant to the revenue requirements established by the department under Section 80110 for the period from January 1, 2013, through December 31, 2018. The revenue requirement shall remain in effect until January 1, 2036

### **Water Code Sec. 80524(b):**

If, pursuant to Section 3289 of the Public Utilities Code, the commission makes a just and reasonable determination with respect to the revenue requirement, then the commission shall enter into an agreement with the department with respect to charges under Section 3289 of the Public Utilities Code with respect to the revenue requirement, and that agreement shall have the force and effect of an irrevocable financing order adopted in accordance with Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the Public Utilities Code, as determined by the commission. The agreement and financing order shall provide for the administration of the revenue requirement, including provisions to the effect that (1) the department shall notify the commission each year of the annual collections received by the department with respect to the revenue requirement and the amount of any excess or deficiency in collections above or below the revenue requirement and that the commission shall adjust charges in the subsequent year to reflect any such excess or deficiency, and (2) during any revenue requirement period if the department forecasts that the revenue requirement for that period will not be met and that collections will not be sufficient to fund any of the amounts in paragraphs (1) to (5), inclusive, of Section 80544, then the department shall notify the commission in writing and the commission shall act within 30 days to increase charges so that the amounts collected during that period are sufficient to meet those obligations. For avoidance of doubt, no such adjustment to charges by the commission shall affect in any respect the commission's just and reasonable determination with respect to the revenue requirement.

**Water Code Sec. 80540(a):**

The department may incur indebtedness and issue bonds as evidence thereof solely for the purposes of supporting the Wildfire Fund and other related expenses incurred by the department pursuant to this division, provided that bonds may not be issued in an amount the debt service on which, to the extent payable from the fund, is estimated by the department to exceed the amounts estimated to be available in the fund for their payment.

**Water Code Sec. 80540(b):**

The department may authorize the issuance of bonds, excluding any notes issued in anticipation of the issuance of bonds and retired from the proceeds of those bonds, in an aggregate amount up to ten billion five hundred million dollars (\$10,500,000,000).

(End of Attachment B)