BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.	Investigation 15-08-019 (Filed August 27, 2015)

COMMENTS OF THE CENTER FOR CLIMATE PROTECTION IN RESPONSE TO THE JOINT ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING ON PROPOSALS TO IMPROVE THE SAFETY CULTURE OF PACIFIC GAS AND ELECTRIC COMPANY AND PG&E CORPORATION DATED JUNE 18, 2019

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Submitted July 19, 2019; Resubmitted July 22, 2019

Introduction

The Center for Climate Protection ("Center") is a California 501(c)(3) nonprofit organization founded in 2001 with a mission to deliver speed and scale greenhouse gas reductions, starting in California. The Center thanks the Commission for this Ruling establishing a process for parties to comment on proposals regarding alternatives to PG&E's current management and operational structures. Critical review of PG&E's corporate governance, structure and operations, and consideration of alternatives are urgently needed not only to address immediate concerns about safety and reliability of electric and gas service in the face of increased environmental volatility (e.g., ongoing fire risks), but also to determine how PG&E can best be structured to implement California's energy and environmental policies, particularly decarbonization of our energy systems and of the economy more generally.

Our Comments focus primarily on instances where an issue or question relating to safety may have a prospective resolution that also has greenhouse gas reduction implications. As directed in the Order, our Comments are presented in six main sections 1 through 6 below, corresponding to the Issues presented in the Order.

1. Separating PG&E into Separate Gas and Electric Utilities

The Center does assert that separating PG&E into separate gas and electric utilities (or selling the gas assets) to address PG&E's large size and to provide a narrower safety focus is necessary. It is necessary for the reasons stated in the Order – enabling a greater focus on providing safe, reliable, and affordable service in both a gas and an electric-only company, and also to facilitate the different longer-term prospects for these two services, i.e., expansion of electricity service versus reduction of natural gas service. In addition to the safety and reliability aspects, an electric-only utility would no longer have a disincentive to promote fuel switching from gas to electric by its customers. The ability of an electric utility to promote fuel switching is important to the Center. Given that the State is on a trajectory for an ever cleaner energy supply for electricity generation, fuel switching from gas to electricity is a significant decarbonization measure.

If there is any question about whether separation is doable, in their own February 13, 2019 Opening Comments in this Investigation, PG&E stated that such a separation "appears feasible from a technical and operational perspective" given that the gas and electric systems are "functionally independent from one another" and each has its own control center.

Responses to Issues/Questions:

A. What research or examples are there that show that separation of the utilities would lead to enhanced safety?

The most recent evidence can again be found in PG&E's own February 13, 2019 Opening Comments in this Investigation where PG&E stated that such a separation has the potential to reduce the total risks managed by any single entity and that "this could increase operational focus by each entity and improve the development of each entity's safety management system." PG&E also stated that if the companies were separated, each would probably "be of sufficient scale to continue to respond to emergencies and would have sufficient expertise in the compliance and risk management functions."

A. (continued) Are there safety benefits that result from the operation of a combined gas and electric system under single management that would be lost with separation?

We were unable to find any examples of safety benefits that might be lost with separation.

B. Can greater focus on safety be accomplished by restructuring the electric and gas business units in other ways? How much of a split is needed (i.e. could they be part of one holding company or otherwise affiliated, or should there be a sale of gas assets to a third party)?

We turn that question around. What case can be made that the gas and electric functions being combined under a single holding company enhances safety? Yes, they certainly *can* be part of the same holding company, but we are at a loss to identify any safety or other public advantage with this structure. Splitting versus selling to a third party results structurally/functionally in the same thing, two completely separate entities.

C. How would separate electric and gas utility service in Northern California impact customer bills and service? Would two separate utilities result in overall higher costs and burdens to customers (such as two bills instead of one)?

The additional costs to ratepayers previously referenced by PG&E and other parties in this Investigation largely revolve around duplication of administrative functions, and the dual customer billing concern is realized only for customers that retain both gas and electric service. Over the next two decades the Center anticipates a decline in fossil gas delivery leading to cessation of the industry altogether as a matter of State decarbonization policy. As the movement for electrification builds and electric devices for space and water heating, etc., become ever more cost effective, it is plausible that many customers will choose to entirely avoid the need for gas service and go all electric. In such cases those duplicative costs are never imposed on the customer. Note that we are using the term "customer" in this discussion and not "ratepayer," given that there are choices involved.

Electricity bills are complex and difficult to understand for most ratepayers. Splitting the gas and electricity services would bring a degree of simplification and clarity given that customers would not be required to parse out the gas component of their bill when attempting to zero in on where their energy usage is high or costly. From this perspective separate billing is both an information resource for the customer and an additional incentive to eliminate gas.

2. Establishing Periodic Review of PG&E's Certificate of Convenience and Necessity ("CPCN")

The Center supports instituting a periodic review of the CPCNs of all the utilities the Commission regulates as this measure constitutes what we consider a best practice. Especially given the rapidly changing nature of the electricity landscape in California, a periodic review may open up opportunities to evaluate the degree to which monopoly status is needed.

A. Are there studies, research or examples that support the thesis that establishing a CPCN review process will change utility leadership behavior towards improved safety performance, or other public benefits?

No Comment – this section is intentionally left blank.

B. What period of time provides the right balance of business and regulatory certainty, along with effective oversight? How long would a CPCN run in between reviews or renewal?

No Comment – this section is intentionally left blank.

C. How would establishing CPCN review process affect the utility's ability to raise capital or willingness to invest in infrastructure?

No Comment – this section is intentionally left blank.

D. What would happen if a CPCN was not renewed? Who would take over, and how can we be assured that they would be any better?

Presumably non-renewal of the CPCN would be based only partially on PG&E's performance, but moreso on factors that include viable alternative owners/operators and/or systems in a changing electricity system. Prior to revoking the CPCN, such arrangements for alternatives should be in place.

E. What cost considerations are there associated with a CPCN review or renewal process? Do the potential benefits outweigh the likely significant transaction costs of a review or renewal process?

No Comment – this section is intentionally left blank.

3. Modification or Elimination of PG&E Corp.'s Holding Company Structure

No Comment – this section is intentionally left blank.

4. Linking PG&E's Returns to Safety Performance Metrics

The Center strongly supports performance-based regulation/ratemaking (PBR), tying PG&E's profits to a set of safety and other performance metrics. There is a vast amount of industry research and expertise on the subject of PBR to assist the Commission in formulating effective rules and incentives for PG&E. See for example, Regulatory Assistance Project's "Next Generation Performance Based Regulation" (May 2018):

https://www.raponline.org/knowledge-center/next-generation-performance-based-regulation-volume-2-primer-essential-elements-of-design-and-implementation/?_sf_s=PBR

And the Advanced Energy Economy 2018 Policy Brief on PBR:
https://info.aee.net/hubfs/PDF/PBR.pdf

A. If you support this approach, please include any available specific examples where similar performance-based incentives have resulted in improved safety performance or other public benefits.

At least twelve other states are exploring PBR, several, such as Illinois where a degree of PBR was instituted in 2012, are beginning to show results. This article in Forbes offers a good overview:

https://www.forbes.com/sites/energyinnovation/2018/05/07/americas-utility-of-the-future-forms-around-performance-based-regulation/#493ab0532bb2

Here are a few write-ups about specific states:

Minnesota: https://www.utilitydive.com/news/puc-order-keeps-minnesota-ahead-of-the-curve-on-performance-based-rates/545797/

Hawaii: https://www.greentechmedia.com/articles/read/performance-based-ratemaking-becomes-law-in-hawaii#gs.qe8p7z

Illinois: https://energynews.us/2017/04/27/midwest/after-five-years-illinois-smart-grid-buildout-showing-results/

The Center would also like to suggest that Commission may want to expand the range of industries included in a survey of PBR effectiveness. The survey could go outside the utility industry and consider safety performance metrics and tools that have been used to achieve high safety standards in other industries such as the airline and coal mining industries. Additionally, financial leverage may include fines and litigation losses for poor performance as well as rewards for good performance. There are probably examples of how fines in certain industries have induced safety changes, and the effectiveness of those fines might be found in the academic literature.

B. What metrics should be used to measure performance? Please be specific in your response, including the extent to which the proposed metric is adequately developed and measurable for this purpose.

The primary immediate risk to be mitigated, but certainly not the only one, is transmission and distribution (T&D) infrastructure coming into contact with foliage. A fundamental means of mitigating this risk is to reduce the instances where such contact exists. PG&E and other utilities can continue to spend millions upon millions to trim trees every year, or they can look to entirely different solutions. Non-wires systems can obviate the need for existing and new T&D infrastructure. That is in fact the theme of this entire set of Comments. Non-wire distributed energy resources (DERs) may be considered to be a preferred way to increase safety via solar+storage and islandable microgrids, with safety/resiliency-based financial incentives to support them. Such systems can serve at least two purposes: (1) as a means to allow more and longer public safety power shut-offs since communities would then have those resources to sustain electric service during extended outages, and (2) to attain performance factors like GHG reduction/decarbonization and transmission and distribution infrastructure cost avoidance.

Therefore, the performance metric we suggest is a metric based on the degree to which PG&E is investing in, supporting, and facilitating community-level DER deployment throughout its service area. See more detail on this suggestion in Section 6, Additional Proposals.

C. What is the range of incentives/disincentives that would be both effective and workable (i.e. how much should the return on equity vary up or down based on achievement of metrics)?

The Commission's job is to translate the level of required incentive/penalty to the scale of the utilities and into the mode of penalty/incentive, either as a direct dollar amount or change in return on equity (ROE).

D. Should this be applied to an overall rate of return or to a return on equity or to some other measure?

The penalty needs to be on the ROE as the CPUC doesn't control the debt rate (the debt rate is market driven), and the Commission probably doesn't want to adjust the capital structure for this aspect. The other option is a direct dollar penalty, however this has only a one-time impact whereas the ROE change can last several years and even resets the benchmark for updating the ROE in future.

E. Please identify any potential unintended consequences or perverse incentives, such as underreporting of safety problems, or focus on safety to the detriment of other objectives, such as costs and reliability? Please include specific examples where similar performance-based incentives have resulted in adverse outcomes.

A focus on safety will most definitely lead to less emphasis on cost controls, especially if the utility perceives that those costs will be passed through in rates. In addition, the utility has an incentive to overestimate the submitted cost with the knowledge that the Commission will reduce the initial request (this has been an ongoing problem before safety issues came up). The best way to contain the utility's tendency to overestimate costs is to allow customers to depart utility service in some fashion. This can be accomplished in several ways. One way is to allow customers to move to self-service through DERs without incurring safety-related exit fees. Another would be to benchmark the utility's rates against regional municipal utility rates. This would involve adjusting the municipal rates for access to subsidized federal power and differences in customer loads. If the IOU's rates exceed the benchmark by a certain percentage (e.g., 10%), communities would be allowed to establish their own utility by acquiring the distribution system at replacement cost new less depreciation. The CPUC has approved other municipal acquisitions using this method.

5. This section intentionally left blank

6. Additional Proposals

In the December 21, 2018 *Assigned Commissioner's Scoping Memo and Ruling*, and in the June 18 Ruling, the Commission invited proposed alternatives for addressing "the ability of the state to implement its energy policies, including the need to reduce greenhouse gas (GHG) emissions and local criteria pollutants in both the utility sector and the economy as a whole."[1] Thus the Commission clearly recognizes that this Investigation must look not only at near-term

[1] *Assigned Commissioner's Scoping Memo and Ruling,* December 21, 2018, at 2.

concerns about safety and reliability in the face of more extreme and unpredictable disruptions, but must also consider how PG&E will be able to most effectively fulfill its roles and responsibilities in achieving California's decarbonized future. It is this latter concern to which Center focuses its comments and offers a proposal for modifying PG&E's structure, regulatory framework and incentives. The Center's proposal will also address other near-term concerns outlined in the Ruling.

6.1 Summary of the Center's proposal

For California's energy systems and society at large to achieve the decarbonization, resilience and justice demanded by climate disruption, state policy and regulation needs to support and work with communities throughout the state, to enable them to plan and implement local energy resources that meet local priorities, align with major state policy goals, and help reduce costs for the electric power system. The IOU electric distribution utilities will be key partners in this project, provided some changes are made to their functions and incentives as described below.

Although PG&E is the focus of the present inquiry, the changes the Center proposes could apply to the other IOU distribution utilities and help form the basis of a uniform regulatory framework for evolving electric distribution service to meet today's needs.

The Center's proposal assumes that PG&E will continue to provide electric distribution service in its service area (with or without retaining the gas side) and sets aside possibilities of public ownership or other ownership restructuring. This assumption is not essential; the proposal could apply to another entity that takes on PG&E's electric distribution system.

The Center's proposal consists of the following four elements.

1. The Commission should separate and clarify the distinct roles and responsibilities of PG&E's distribution service and its retail energy function (i.e., the load-serving entity or LSE function). Assuming PG&E continues to own and operate its current distribution system, its distribution function should remain a regulated natural monopoly service, but clear boundaries are needed between natural monopoly distribution assets and activities versus the LSE function and other areas where innovation and competition among third parties are more beneficial. For example, ownership and operation of end-use facilities such as EV charging stations or battery storage devices on customer premises is not a natural monopoly function and should not be eligible for rate-base cost recovery. In the rapidly evolving technology landscape of today, keeping competitive activities outside the scope of the regulated monopoly is necessary both to create a level playing field for all third-party innovators and to limit the exposure of ratepayers to technology performance and obsolescence risks.

2. The Commission should restructure PG&E's distribution service function to align better with state policy goals for decarbonization and resilience. Achieving these goals will depend to a large extent on initiatives adopted by local governments to decarbonize buildings, transportation, etc., and to strengthen local resilience to extreme disruptions. These initiatives will entail local energy planning and diverse applications of distribution-connected energy resources (DER), on both the customer side and the utility side of the meter.[2] DERs offer vast potential benefits to both energy end-users and to the whole power system, but today some of the benefits are barely

[2] These comments use the term distribution-connected or distributed energy resources ("DER") broadly to mean the full range of electricity resources connected to the power system at distribution level, on either the customer side or the utility side of the end-use meter, as well as smart inverters and advanced control technologies to optimize their use for both meeting the needs of energy customers and providing grid services to support reliable, efficient power system operation.

recognized much less quantified, and there are substantial barriers to DER commercial viability that regulatory reforms could address.[3]

In order to maximize the value and benefits of the growing volume and diversity of DER on the system and ensure their critical role in achieving California's policy goals, the Center recommends that PG&E's distribution service be restructured as an Open Access Distribution System Operator (OA-DSO). The central concept behind the OA-DSO is analogous to FERC's open-access rules for transmission service and wholesale markets. In California this FERC framework is illustrated by the CAISO's use of transparent market mechanisms for allocating transmission service, its relationship with its participating transmission owners (PTOs), its management of transmission planning and new resource interconnection processes, and its independence from the participants in the wholesale market it operates. This does not necessarily require a new independent DSO ("IDSO") entity, but it does mean that the OA-DSO function will need to perform several key elements, including but not limited to:

a. Well-defined grid services that third-party DER providers, including energy end-users with customer-side DER, can provide to the DSO through non-discriminatory and transparent procurement mechanisms and will be fairly compensated for;

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[3] See Scott Murtishaw (January 2019) "Barriers to maximizing the value of behind-the-meter distributed energy resources," California Solar & Storage Association. This paper provides a detailed examination of DER-related issues raised in some key Commission proceedings and offers specific proposals for how to address them. CCP is not commenting one way or other on Mr. Murtishaw's specific recommendations, but we suggest that reforming the regulation of the utility distribution function as proposed here will create a more favorable context for DER proliferation that will simplify resolution of many of the more granular issues Mr. Murtishaw identifies. https://static1.squarespace.com/static/54c1a3f9e4b04884b35cfef6/t/5c509f774ae23756e03f6161/1548787577591/CALSSA+Whitepaper+on+DER+Barriers-Jan2019.pdf

b. An open, participatory distribution planning process that provides sufficient information on identified upgrade needs and opportunities for third parties to submit preferred-resource alternatives and have them fairly evaluated;[4]

c. Streamlined interconnection processes to facilitate development of community-level DER (such as solar + storage) on the utility-side of the meter and formation of community microgrids to ensure continued availability of power to critical and priority facilities in the event of a major system disruption and to enable safety-related de-energizing of a line under high-risk conditions (public safety power shutoffs or PSPS);

d. Transparent real-time operating procedures that govern curtailment of DER or other mandatory operating instructions, to ensure such procedures are non-discriminatory in their application to third-party assets;

e. A transmission-distribution coordination framework with CAISO to ensure reliable operation and market integration with high volumes and diversity of DER on the system; and,

f. A data access framework that enables the above elements to work efficiently and with non-discriminatory participation by prosumers and third-party providers.

3. Develop performance-based regulatory ("PBR") rules and incentives for PG&E's OA-DSO function. The central concept of PBR is to shift the basis of the utility's profits from a guaranteed rate return on assets to well-defined metrics that measure the quality of the DSO's performance of the activities it is responsible for. Under a PBR structure PG&E could still recover the costs of infrastructure investments, but at a rate of return that's closer to its actual cost of capital while performance metrics provide more of the basis for the DSO's profit.

[4] The CAISO's annual Transmission Planning Process offers a useful model for how a new distribution planning process could be structured.

4. The Commission should recognize and direct the OA-DSO to facilitate the crucial role to be played by local governments and communities in achieving California's climate, energy and equity goals.[5] Many of the factors that drive carbon emissions are in the realm of urban and county planning: housing density, transport-oriented development, building codes, land use and zoning, traffic and mobility services, etc. Local governments are also key actors in creating greater safety and resilience for the more volatile environment we now inhabit, and in addressing equity issues and the needs of disadvantaged communities. And since many of these initiatives will involve electrification of fossil-fuel-using activities and will drive new demand for electricity, the DSO needs to be a collaborative partner in the design and implementation of local energy resources. On that point, the Commission's list of factors for evaluating proposals includes the following: "the utility's relationships with and role in local communities."[6]

To that end the Commission should direct PG&E's OA-DSO function to be an effective collaborator with local governments and their relevant agencies to develop and implement electrification and resilience-related energy projects that address community needs in alignment with power system benefits. In essence this means crafting a convergence between power system planning and city/county planning. PG&E's performance on this requirement should be an element of its PBR-based compensation.

The rest of this section is organized as follows: Section 6.2 describes some outcomes and desirable features of a future decarbonized California energy landscape that may be viewed as targets or objectives to which regulastory policies should aim. Section 6.3 identifies legacy 20th

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[5] For expanded discussion of these ideas, see Lorenzo Kristov (November 27, 2017) "Comments in response to the October 31, 2017 informal public workshop on California Customer Choice." http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Lorenzo%20Kristov%20Comments.pdf

[6] *Assigned Commissioner's Scoping Memo and Ruling*, December 21, 2018, at 10.

century features of PG&E's current structure and regulatory framework that are in conflict with the desired future. Section 6.4 then outlines the Center's proposed changes to the current structures, and Section 6.5 offers elements of a transition approach.

6.2 The pathway to California's decarbonized future

Consider California's energy landscape in 2030, starting with the electric power system which must deliver 60 percent renewable energy by then. While much of the industry is polarized by a debate between a vision of the future dominated by bulk electric system ("BES") renewable resources in an optimized western regional grid versus a future dominated by rapid growth of DERs and community power systems, this is a false dichotomy. The power system in 2030 should be a blend of bulk system and decentralized resources for reasons discussed below. However, today's power industry institutions and the dominant industry culture are biased toward building "utility-scale" BES infrastructure and tend to be dismissive of the role of DER and community power systems,[7] which are inherently more beneficial from resilience and safety perspectives. It is important to understand why DER and community power systems are valuable and even crucial to California's goals, and to implement changes to PG&E's regulatory framework and incentives that will promote their growth.

DER and community power systems offer the following capabilities and benefits that can shape a safe, reliable, efficient, low-carbon California power system by 2030:[8]

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[7] These comments use the term "community power system" to mean a system of carbon-free DER and provisions for coordinating their operation, designed and implemented through state-local collaboration to: (a) support the reliable operation of a carbon-free, secure and efficient electric power system; (b) meet local energy, resilience and electrification needs; (c) achieve California's environment, energy and equity goals; and (d) provide economic, employment and other benefits to communities.

[8] The year 2030 holds a number of key milestones in California policy. Senate Bill 100, signed into law by Governor Brown in 2018, requires electricity consumed in the state to be 60 percent from renewable supply resources by 2030. SB-32 passed in 2016 requires a 40 percent reduction in greenhouse gas emissions below 1990 levels by 2030, and a Governor's executive order sets a 2030 target for 5 million zero-emissions vehicles. For additional milestones and

1. **Electrification.** A major share of projects and strategies to electrify transportation and buildings and more broadly reduce carbon emissions from all sources will come about through city and county planning. General Plans deal with such matters as zoning, building codes, housing densification, affordable housing, traffic and mobility services, land use and habitat protection, etc. As buildings, transportation, and agriculture come to rely more on electricity, coordinating power system planning with city and county planning will enable optimal tradeoffs between local DER and BES-level supply, to electrify current fossil-fuel uses in the most cost-effective and societally beneficial manner, taking into account local resilience and equity benefits in addition to the usual energy cost considerations.
2. **Shaping net load and managing volatility locally.** Customer adoption of DERs will continue to grow with declining costs and increasing capabilities of new local-scale technologies. Combined with electrification-driven demand growth, the resulting increased volatility and extreme production and net load profiles at the grid edge and the circuit level (e.g., "ducklings") can be managed locally using flexible DER and storage at various scales, rather than exporting grid-edge impacts upstream to create operational challenges and drive infrastructure needs at the BES level.
3. **Alternatives to expanding costly and vulnerable grid infrastructure.** There is no reason anymore to build T&D infrastructure to meet peak loads that occur infrequently and leave vast amounts of capacity underutilized most of the time. Flexible DERs, including load management and control systems, can create relatively flat net load profiles at both the distribution circuit level and BES level, enabling rapid growth of

targets see the California Air Resources Board's Scoping Plan: https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm carbon-free local energy supply without driving costly T&D capacity expansion and troublesome "duck curve" impacts. (Adoption of PBR as noted above should mitigate incentives to expand grid infrastructure.) Relatively flat, predictable net load profiles at transmission-distribution interfaces can reduce congestion and increase capacity factors on the BES, enabling it to move renewable energy supplies around the western region with less need to invest in massive new grid infrastructure.

4. **Resilience.** While resilience has become a national hot-topic with many notions about what it means and how to achieve it, disruptive events always have local impacts that can drastically affect people's lives, in many instances fatally. At the local level, resilience objectives include the capability of essential services and infrastructure to withstand more extreme events and continue functioning, the ability to quickly restore or substitute for essential services that fail, and the ability to activate public safety power shutoffs (PSPS) of at-risk T&D lines without totally cutting power in downstream communities. Thus a local resilience strategy is to create power systems at different levels that can operate as electrical islands, i.e., microgrids. A microgrid can be entirely on the customer side of the meter, e.g., an individual building or a campus that does not rely on DSO facilities or services upstream of the point of interconnection, to enable a critical facility such as a hospital or emergency shelter to operate off-grid. A microgrid can also serve a larger community by coordinating the operation of multiple single facilities and utility-side DERs to sustain electric service over one or more distribution circuits on the DSO grid in coordination with the DSO's distribution service.
5. **Local and statewide economic benefits.** Once we start to advance community power systems designed and implemented collaboratively with the DSO, it opens up numerous

job opportunities and diverse economic benefits for disadvantaged communities, cities and counties and all their residents.

To summarize, DER and community power systems offer the potential to achieve major advances in electrification of transportation and buildings with little increase in demand on the BES, even though total electricity consumption could be much greater than today. Key to this outcome is for PG&E's OA-DSO to partner with local planning in all communities across the state. As a result, new electrification demand can mostly be met with local supply and storage resources, while new energy efficiency programs implement weatherization retrofits in the state's entire building stock, and customer-side of the meter technologies transform electricity end-users into flexible resources providing grid services. These local programs can provide hundreds of thousands of well-paying jobs and bring economic benefits to low-income communities, while also reducing congestion on the western grid and moving power from wind and solar rich areas to population centers without having to build massive new infrastructure.

Now consider how California can decarbonize major fuel-intensive activities outside of the electric grid itself, mainly transportation and buildings. Transportation electrification requires much more than people swapping a combustion engine for an electric vehicle. By 2030, with bold initiatives by local governments and state support for planning and projects in all communities, reliance on private cars in urban areas can be diminished immensely. To take climate adaptation and decarbonization seriously, city and county planning must place sustainability and resilience at the center of all decision making, such as: housing densification in core areas rather than sprawl; affordable housing close to public transit hubs and close to where people work (transit-oriented development); motor-vehicle-free downtown areas with new clean mobility services to move people to and from their destinations; building codes that require energy efficient buildings and all-electric new construction (avoiding new gas infrastructure that will soon be stranded); microgrid features to enable critical and priority facilities to operate as electrical islands; natural sustainability measures such as tree canopy, storm water capture and aquifer replenishment, as well as insect, bird and wildlife habitats and corridors. Many of these measures point to a need for collaboration between electric distribution system planning and city/county planning. The next two sections describe the legacy industry structures in need of updating and the policy actions to achieve the needed reforms.

6.3. Legacy Utility Structure Does Not Well Serve 21st Century Needs

To identify the most effective policy changes it is necessary first to understand how PG&E's existing structure and the regulatory and incentive framework in which it operates constrain California's ability to achieve rapid cost-effective decarbonization throughout the state. The existing structure was created in the last century to expand energy service and supply infrastructure and grow energy consumption rapidly. But now society's needs have shifted while the existing structure continues to embody these legacy characteristics:

1. **Expensive large-scale infrastructure is paid for by captive customers through regulated retail rates.** Traditional power system investment is supply focused, assuming demand to be exogenous, resulting in excess capacity most of the time, with all risk of stranded investment placed on ratepayers, not on the utility companies or their investors. Today DERs are able to both meet and shape electricity demands close to their source to dramatically reduce the need to invest in BES and distribution system infrastructure even while consumption grows due to electrification. The Commission needs to align DER investment incentives and opportunities with this new reality.

2. **PG&E's compensation is based on the cost of physical assets rather than the quality of service, which incentivizes them to develop large infrastructure projects and to impede growth of DER that can offset the need for large infrastructure.** Today the impediments appear in the form of costly interconnection procedures, opaque distribution planning processes with limited opportunities to adopt carbon-free non-wires alternatives, and multiple complex regulatory proceedings moving very slowly to open the field for competitive, cost-effective DER services. Updated processes for infrastructure planning and selection of preferred solutions would provide ratepayer/customer benefits by adopting more cost-effective technology solutions with less risk of stranded assets, but this requires tying PG&E's OA-DSO compensation to clear metrics for performance of its defined roles and responsibilities.
3. **Lack of clear boundary between PG&E's "natural monopoly" functions (owning and operating the systems of wires and transformers) versus functions where open competition would improve results for energy customers (e.g., investment in "grid edge" devices like EV charging stations).** When FERC created the framework for wholesale power markets in the 1990s, the central principle was open-access transmission service, which is provided in most of the country today by independent system operators, unaffiliated with market participants and with the owners of the transmission assets under their operational control. Today in California there is still no similar unbundling of PG&E's distribution function. One consequence is that as PG&E seeks to expand rate-based asset holdings into new technology areas, they enjoy competitive advantages by, for example, having unique access to customer data held by their distribution function and reduced risk due to guaranteed cost recovery through rates. An urgent issue for the

Commission is to define new boundary principles between PG&E's regulated monopoly functions and competitive functions, so as to realize the greatest societal advantage to the vibrant DER technology innovation in progress today.

4. **PG&E has a huge service area under a regulatory framework that requires uniform service offerings and cost allocation and precludes providing more tailored services to different communities.** This is also a legacy structure based on historic economies of scale and the construct of electricity as a homogeneous commodity that can only come from the grid. Today these rationales no longer apply, and the new goals of electrification and resilience require locally-designed DER-based energy systems. Until the advent of Community Choice agencies, the only way for a local government to shape its energy supplies and practices was to form a municipal electric utility. But at this moment the CCA model is preferable to municipalization because it leaves in place PG&E's distribution wires function, retains its workforce and expertise in distribution system planning and operation, and avoids the need to transfer ownership of assets. If the Commission adopts requirements for partnership between PG&E's OA-DSO function and local governments, including CCAs where they exist, it can expedite locally-based electrification and resilience initiatives and offer a viable 21st century OA-DSO business model for PG&E.

5. **Too much weight is placed on benefit-cost analysis ("BCA") as a basis for policy and investment decisions.** BCA claims to be an objective tool for making decisions, but in practice it cannot objective, so its results should be seen as data points, not definitive answers. BCA's results depend on which benefits and costs are included and how they are measured. But policy decisions are future oriented, intended to achieve future benefits

that are excessively discounted based on prevailing financial rates of return, or may not yet have measurement methods. Indeed, benefits of greatest concern in the era of climate disruption — e.g., local resilience and our grandchildren's quality of life — have thus far been too hard to quantify. Thus, BCA has an inherent bias toward preserving the status quo, and therefore it's often used to preclude an otherwise feasible and desirable solution on the grounds that it "doesn't pencil out." As the Commission considers alternatives to address the issues raised in the Ruling, it should bring these urgent but hard-to-quantify, hard-to-monetize societal values into the center of the proceedings.

6.4. Elements of a 21st Century Electricity Policy Framework

The Center recommends that the Commission approach reforms to PG&E's current structure through adoption of the following major elements:

1. Reform PG&E's electric distribution function to become an open-access distribution system operator (OA-DSO), based on an open-access structure analogous to the CAISO's structure for providing non-discriminatory transmission service and operating wholesale spot energy markets, but designed for the characteristics and operation of electric distribution systems.
2. The open-access structure should include competitive market mechanisms whereby participating energy customers, DER providers and LSEs can develop and be compensated for grid services to the DSO, including deferral of grid asset investment as well as real-time operational services such as voltage support, congestion management and phase balancing. The framework must clearly define details of each distribution grid service, including performance requirements, dispatch, measurement and compensation.

It must be non-discriminatory with regard to system planning, interconnection procedures and real-time operations such as curtailments, and these activities must be subject to clear transparency standards and supported by an effective data access framework. This will create a needed foundation for expanding cost-effective DERs on the system, for the commercial viability of DER innovators and providers, and for designing local electrification and resilience projects.

3. Develop and adopt PBR rules and incentives for PG&E's OA-DSO that measure the DSO's performance of specific roles and responsibilities and compensate the utility based on those measures.
4. Include in the PG&E DSO's mandate a requirement to partner with local governments to develop and implement electrification and resilience projects, bringing together city and county planning with power system planning.
5. Implement data access provisions for PG&E's OA-DSO that enables cities and counties to plan electrification and resilience projects and third-party DER developers and CCAs to develop local resources to implement those projects. It is both necessary and possible to protect customers' rights to privacy and control of their own data, and address infrastructure security concerns, without placing the control under a for-profit monopoly that can realize financial benefits from control of information. Having customer data under PG&E's control is a single major impediment to enabling the demand side to become effective managers of their own impacts on the grid and providers of grid services. From a cost perspective, data access is yet another challenge to third parties seeking to develop non-wires alternatives to grid infrastructure upgrades.

6. Redesign distribution system planning to accommodate broad electrification, resilience and DER growth, and to include an analog to the "loading order" in procurement which establishes preferences for energy efficiency and active customer participation in grid operational needs, and for carbon-free, DER-based non-wires alternatives to grid infrastructure. Distribution planning must become transparent and include meaningful stakeholder participation and opportunities to offer alternative solutions. Distribution planning must also address staged "no regrets" approaches to grid modernization, with PG&E's compensation for such investment based on performance of distribution services rather than straight return on assets.
7. With separation of PG&E's distribution function from its retail function, the Commission needs to reconsider the roles and responsibilities of PG&E's retail function going forward. PG&E's retail kWh service will no longer be "bundled" as it has been historically but will be provided by a distinct functional unit of PG&E whose relationship to the OA-DSO is comparable to that of other non-utility LSEs. With so much of PG&E's load migrating to CCAs, and given the greater flexibility CCAs have to develop local resources to meet local needs and provide grid services (especially in the context of the DSO reforms the Center proposes), it is reasonable to ask whether PG&E wants to retain its LSE function. If PG&E's retail function is no longer under a regulated monopoly framework, it would seem logical to allow PG&E to make this decision for itself (setting aside issues related to bankruptcy). At the same time, there remains an open question about provider of last resort ("POLR"), i.e., the question of who provides retail service to a customer who opts out of a CCA or whose alternative LSE ceases to function. There are examples from other states of different approaches to POLR the Commission may

consider in a proceeding on transition issues. In the meantime the Center recommends that the Commission not assign any additional procurement responsibilities to PG&E until these more basic utility structure provisions can be addressed.[9]

8. The Center fully supports the Commission's adoption of strong oversight of PG&E's performance on reliability and safety of its transmission and distribution systems and explicit tying of PG&E's compensation to metrics in these areas as well as for the other responsibilities discussed above.

6.5. Transition Considerations

The Center recognizes that the reforms we propose to PG&E's operational structure represent significant changes to today's arrangements. At the same time, these or similar reforms have been topics of industry discussions in California and other jurisdictions for many years, and some elements of the reforms are already being addressed to some extent in ongoing Commission proceedings. The Commission could take up the Center's proposals as follows:

1. At the earliest feasible date open a rulemaking to define the functional elements and regulatory framework for PG&E's distribution function to become an OA-DSO, incorporating the elements described above. This rulemaking should also develop safety and other performance metrics for the OA-DSO's roles and responsibilities and specify their use in determining PG&E's compensation.

[9] For example, the November 21, 2018 Proposed Decision in the Commission's Resource Adequacy Track 2 proceeding (R.17-09-020) proposes to assign the IOUs the role of central buyers for 100 percent of Local Resource Adequacy capacity needs starting in 2019 for the 2020 compliance year. CCP agrees with the many parties who have formally urged the Commission to defer assigning this role to the IOUs to take more time to consider alternative approaches; in view of the issues the Commission raises in this Investigation and the clear need for fundamental reforms to PG&E's structure, it does not seem prudent to assign such an important new function to PG&E at this time.

2. Within the DRP proceeding (R.14-08-013), define the structure of a cyclical, reformed PG&E distribution planning process, including stakeholder participation and information access provisions, that will facilitate coordination of power system planning with city and county planning for electrification and resilience, support design and implementation of community-level power systems and microgrids, and allow transparent comparison and adoption of zero-carbon DER alternatives to expanding grid infrastructure.
3. Within the IDER proceeding (R.14-10-003), develop the rules for a competitive distribution grid services market in which third-party DER providers, including end-users with customer-side DER, can provide and be fairly compensated for grid services to PG&E's OA-DSO. The proceeding has already made some progress on grid services such as voltage support and congestion relief to support DSO operation (see decision D.16-12-036), and now it needs to develop the details, including performance requirements, measurement, procurement mechanisms and compensation.[10] These should be framed in a technology-neutral manner so as to foster innovation, competition and broad participation.

Conclusion

The Center thanks the Commission for providing this opportunity to offer ideas and proposals for the reform of PG&E's management and operational structures. We believe that the recommendations we offer will both provide a more solid basis for oversight of the safety and reliability issues the Commission has raised, and create an OA-DSO structure that is aligned with

[10] Building on D.16-12-036, in 2018 PG&E, SCE and SDG&E jointly completed additional work to advance DER-based grid services and provided recommendations for next steps. See the Smart Inverter White Paper and Appendix: https://aeic.org/committees/power-delivery/distributed-energy-resources-subcommittee/

California's climate and equity goals and enables society to realize the greatest benefits of ongoing trends in customer adoption of DERs and DER technology evolution.

Respectfully submitted,

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July 22, 2019