EXHIBIT 1

AFFIDAVIT OF ROBERT JENKINS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Public Utilities Commission, Northern California Power Agency, City and County of San Francisco, State Water Contractors, and Transmission Agency of Northern California, *Complainants*, v. Pacific Gas and Electric Company, *Respondent.*	Docket No. EL17-___-000

AFFIDAVIT OF ROBERT JENKINS ON BEHALF OF COMPLAINANTS

1. My name is Robert Jenkins. I am currently a Managing Consultant with Flynn Resource Consultants Inc. My business address is 5440 Edgeview Drive, Discovery Bay, California 94505.

2. I graduated from North Carolina State University in 1980 with a Bachelor of Science degree in Electrical Engineering and from Rensselaer Polytechnic Institute in 1981 with a Master of Engineering degree in Electric Power Engineering. I am a Registered Professional Engineer in the state of California and a Senior Member of the Institute of Electrical and Electronics Engineers.

3. I was employed by Pacific Gas and Electric Company (PG&E) from 1981 to 2001 where I performed various engineering and management roles in transmission planning including:

- Power systems analysis and development of electric transmission project proposals,

- Transmission—related regulatory support, including serving as PG&E's transmission capital witness in ER01-66, PG&E's fifth transmission owner rate case, and
- Business support with respect to PG&E's wholesale customers including transmission interconnections.

4. From 2001 to 2012, I was employed by Mirant Corp. (2001-2005), PG&E (2005-2008), and First Solar, Inc. (2008-2012) to manage each company's electric transmission interconnection activities for their new conventional and renewable resource development. My responsibilities included participating in interconnection activities associated with specific generation projects, and developing and advocating for regulatory positions on electric transmission and interconnection issues. Since 2012, I have been employed by Flynn Resource Consultants Inc., where I provide various technical and commercial electric transmission services. These activities include participating in the California Independent System Operator's (CAISO) Transmission Planning Process (TPP) on behalf of our clients and assisting them in the preparation of comments on study methods and proposed transmission projects. I have also been actively involved at the Western Electricity Coordinating Council where I am a member of the Planning Coordination Committee after serving as its Chairman from 2005 to 2007.

5. I have previously testified before this Commission with respect to electric transmission matters in proceedings EL89-4, ER95-980, OA96-28, ER97-2358, EL99-68, ER99-4323, ER00-2360, ER01-66, ER04-1110, and EL15-3-002.

6. The purpose of this Affidavit is to:

- Provide insight on how PG&E handles transmission planning for its system, the limited role of stakeholders in its transmission planning processes, and what projects are submitted to the CAISO's TPP via the Request Window.
- Evaluate the forecast capital expenditure data provided in Exhibit 9 of PG&E's TO18 rate filing[1] to provide insight on the total value of capital expenditures approved by the CAISO via the TPP versus the total value of capital expenditures not approved by the CAISO.
- Describe how PG&E's three primary electric transmission capital programs that currently lack stakeholder involvement directly impact system reliability and costs for PG&E's wholesale and retail consumers, similar to the issues examined in the CAISO TPP.
- Describe how increased stakeholder involvement in PG&E's transmission planning processes could translate to consumer cost savings.

I. PG&E TO18 CAPITAL EXPENDITURE FORECAST

7. PG&E has presented in its TO18 filing a capital forecast totaling over $2.5 billion for the 2016-2017 period.[2] These capital costs are assigned to twenty Major Work Categories (MWCs) which fall into eight capital programs, including:

- Capacity,
- Electric Substation Management,
- Transmission Line Management,
- System Reliability and Automation,

[1] Pac. Gas & Elec. Co., Transmission Owner Tariff 2017, Ex. PGE-9 (July 29, 2016), eLibrary No. 20160729-5100 ("TO18 Ex. 9").

[2] TO18 Ex. 9 at 65, Table PGE-9-1.

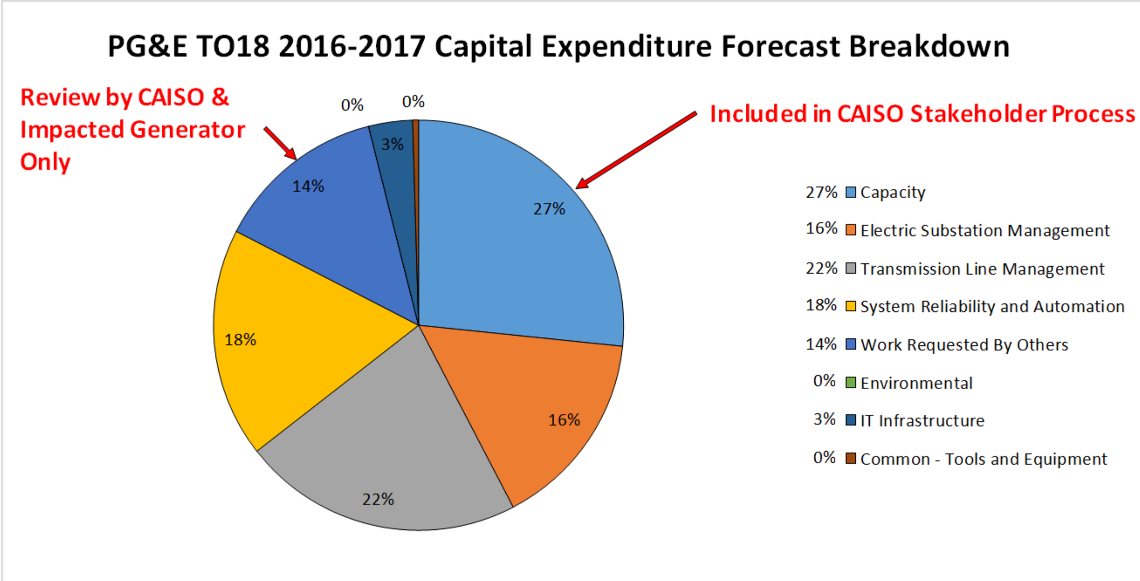
- Work Requested by Others,
- Environmental,
- IT Infrastructure, and
- Common.

8. Of these eight programs, only Capacity projects in MWCs 60 and 61 are submitted to the CAISO's TPP where stakeholders have an opportunity to review and comment.[3] These projects represent at most only 27% of PG&E's total forecasted electric transmission capital expenditure for 2016-2017. In addition, most of the expenditures in the program "Work Requested By Others" (WRO) are generation interconnection-related costs.[4] These projects are not submitted to the TPP, and external review is limited to the CAISO and the interconnecting generator. WRO projects represent 14% of the total forecasted electric transmission capital expenditure for 2016-2017, and include Network Upgrades, the costs of which are ultimately borne by PG&E's end-use transmission customers. The following Figure RTJ-1 provides an overview of PG&E's 2016-2017 capital expenditures by its eight capital programs.

[3] *Id.* at 6 n.2.

[4] *Id.* at 51:17-19.

Figure RTJ-1: PG&E TO18 2016-2017 Capital Expenditure Forecast Breakdown



9. The remaining roughly 60% of PG&E's forecasted electric transmission capital expenditures—$1.5 billion of the projected $2.5 billion—receive no external review. General stakeholder review through the CAISO's annual TPP is limited to $667 million, or just over a quarter, of PG&E's forecasted capital expenditures.

II. PG&E'S TRANSMISSION PLANNING PROCESS

10. PG&E conducts different planning processes for its transmission projects depending upon the type of project. These projects largely fall into three categories. The first of these categories covers projects submitted to the CAISO's TPP. For the 27% of the PG&E TO18 2016-2017 capital forecast that will ultimately be submitted to the CAISO's TPP (i.e., MWC-60 and MWC-61), PG&E has prepared its "2016 Electric Transmission Grid Expansion Plan," a portion of which is attached as Attachment PGE-9-4 to its TO18 testimony.[5] This is an internal PG&E document for which stakeholder input is neither solicited nor considered.

[5] *Id.* at 85.

11. Many of the projects discussed in the PG&E Transmission Grid Expansion Plan were ultimately submitted through the CAISO's TPP "Request Window." For those projects, PG&E presents its selected proposals in a public forum and gives stakeholders an opportunity to provide comments.[6] The CAISO then decides what capacity project proposals to accept into its Transmission Plan.[7] As Attachment PGE-9-4 is incomplete, it is not possible at this time to determine whether PG&E includes any stakeholder feedback from the CAISO process in its Expansion Plan.[8]

12. The second category includes the 14% of PG&E's TO18 2016-2017 capital forecast under its WRO program. The majority of that work, as noted above, is related to generation interconnection projects. For those projects, PG&E participates in the CAISO's Generation Interconnection and Deliverability Allocation Procedures (GIDAP).[9] Under the GIDAP, a generator interconnection application initiates transmission studies by both PG&E and the CAISO to identify system additions deemed necessary to accommodate the level of service requested by the generator as well as all other generators in the same application cluster.[10] Final CAISO study reports for interconnection applications aggregated by geographic region are made available to

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[6] Cal. Indep. Sys. Operator Corp., Fifth Replacement FERC Electric Tariff § 24.4.2 (2016), http://www.caiso.com/Documents/ConformedTariff_asof_Jan1_2017.pdf ("CAISO Tariff"); CAISO Business Practice Manual for the Transmission Planning Process § 4.3.

[7] CAISO Tariff § 24.4.5.

[8] Other proposals in this category were additionally never submitted to the TPP. These include "Transmission Project Proposals Requiring Further Development," "Transmission Access To Renewables," and "Maintenance Replacement Work," all referenced in the Transmission Grid Expansion Plan table of contents. The corresponding pages of the Expansion Plan describing those projects were omitted from PG&E's TO18 filing, and PG&E has neither submitted these proposals to the CAISO through its TPP Request Window nor sought stakeholder input.

[9] CAISO's GIDAP procedures are described more fully in Appendix DD to the CAISO Tariff.

[10] CAISO Tariff Appendix DD § 6.1.3.

stakeholders.[11] These reports identify Reliability Network Upgrades (RNUs) and Delivery Network Upgrades (DNUs) resulting from the study, though they do not identify the Plan of Service RNUs associated with each generator interconnection.[12] Transmission projects identified in the GIDAP are approved by the CAISO in this parallel process and are not included in the CAISO's TPP. As a result, the stakeholders who will ultimately pay for the associated upgrade costs have no opportunity to participate in the process that drives those costs.[13]

13. The third category includes the remaining 60% of PG&E's TO18 2016-2017 capital forecast, which PG&E reviews and approves internally. PG&E employs a two-phase internal approval process. First, management approves the overall budget proposed by PG&E staff. Second, program sponsors within PG&E authorize specific and nonspecific projects within the program up to the total budget approved for that program.[14] Stakeholders first see these projects as line items in PG&E's request to FERC to include the cost in the Transmission Revenue Requirement of its TO Tariff filing. By this point, the projects are approved or even built; it is too late for effective stakeholder feedback.

[11] *Id.* § 3.6.

[12] *Id.*

[13] The exception to this separation of processes is the approval of Area Delivery Network Upgrades (ADNUs). ADNUs are defined by the CAISO tariff as upgrades to relieve deliverability constraints on a substantial number of generators in one or more specified geographic or electrical areas of the CAISO grid. For such upgrades, initial funding is not requested from the generators and the approval of such work progresses through the CAISO TPP as a policy-driven transmission project.

[14] TO18 Ex. 9 at 6:12-7:4.

III. NO STAKEHOLDER INPUT IS RECEIVED ON A NUMBER OF COSTLY PROGRAMS

14. Within the 60% of capital work that receives no external review, the three program areas with the most significant capital expenditures are:

15. *System Reliability and Automation (SRA)*. SRA is primarily focused on efforts to improve reliability through substation infrastructure improvements and integrated protection and controls systems, with a forecast capital expenditure of $453 million for 2016 and 2017.[15] Major cost drivers include the Energy Management System (EMS) Upgrade at $88 million;[16] installing Modular Protection and Automation Control (MPAC) buildings at 38 locations at a forecasted cost of $76 million;[17] and adding bus sectionalizing breakers or converting existing stations to a Breaker-and-a-Half or ring bus configuration at a forecasted cost of $158 million.[18]

16. *Electric Transmission Line Asset Management (ETLAM).* ETLAM is primarily focused on replacement of transmission equipment, which constitutes $523 million, or 94% of the total cost of the program.[19] Within this program, a major cost driver is the North American Electric Reliability Corp. (NERC) Alert Program at $272 million.[20]

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[15] *Id.* at 39:7-21.

[16] *Id.* at 41:13-30.

[17] *Id.* at 42:10-21.

[18] *Id.* at 45:11-12.

[19] *Id.* at 32-37. Replacing transmission equipment includes MWCs 70 (Replace Line Poles and Structures), 71 (Replace Line Right-of-Way Access), 72 (Replace Line Underground), and 93 (Line Preventative Work).

[20] *Id.* at 37:7-9.

17. *Electric Substation Asset Management (ESAM)*. ESAM is primarily focused on replacement of substation equipment,[21] which constitutes $361 million, or 92%, of the total cost of the program.

IV. GREATER STAKEHOLDER INVOLVEMENT COULD LEAD TO SIGNIFICANT COST SAVINGS AND BETTER PROGRAMS

18. Due to aggressive energy efficiency measures and increased penetration of behind-the-meter (BTM) generation (typically rooftop solar), the California Energy Commission staff has forecast a very modest growth projection for the PG&E area, with the coincident peak demand average annual growth rate from 2016 to 2027 of 0.40%.[22] Yet, despite the expected modest load increase, electric transmission revenue requirements are forecast to increase substantially. The current CAISO High Voltage Transmission Access Charge (HV TAC) is forecast by the CAISO to increase from its current $10.68/MWh[23] to $13.91/MWh within the next eight years.[24] This represents a 30% increase in rates at the same time peak load growth is almost flat. (The CAISO does not publish a forecast of the LV TAC rate.) This forecasted average annual increase in HV TAC of 3.4% may even be low, as this is much less than the 9.7% average increase in PG&E's Transmission Revenue Requirement over its past eleven Transmission Owner Tariff filings. The current combined CAISO HV TAC and the PG&E LV TAC represent

[21] *Id.* at 27:6-11. Replacing substation equipment includes MWCs 64 (Replace Substation Breakers), 65 (Replace Substation Equipment-Emergency), 66 (Replace Substation Other Equipment), and 68 (Replacement Substation Transformers).

[22] Cal. Energy Comm'n, *Staff Report California Energy Demand Updated Forecast, 2017-2027* 58, Table 32 (Jan. 12, 2017), http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN215275_20170112T135223_California_Energy_Demand_Updated_Forecast_20172027.pdf.

[23] Cal. Indep. Sys. Operator Corp., September 01, 2016 TAC Rates 1 (Oct. 10, 2016), http://www.caiso.com/Documents/HighVoltageAccessChargeRatesEffectiveSep1_2016_RevisedOct10_2016.pdf.

[24] Cal. Indep. Sys. Operator Corp., Transmission Program Impact on High Voltage TAC, *Estimating Model – 2015/2016 Version* 5, Stakeholder Call (May 23, 2016), http://www.caiso.com/Documents/Presentation-2015-2016TransmissionAccessChargeModel.pdf.

an average of 1.8 ¢/kWh on consumers' energy bills. In simple terms, for a residential customer with a monthly usage of 500 kWh, the combined TAC charge would amount to roughly $9.00 per month.[25]

19. Examples where stakeholders, if afforded the opportunity, could have meaningful input into the projects selected under these programs include the following. In some cases, the result might be that the more expensive project is found worth the costs; in other cases, significant cost savings might result.

A. Substation Configuration Design Preferences

20. These replacement programs reflect long term capital decisions that represent significant cost decisions and opportunities that necessitate stakeholder input. For example, prior to the formation of the CAISO, PG&E's use of a Breaker-and-a-Half (BAAH) substation configuration was limited to 500 kV substations and a few selected substations under 500 kV. Increasing the number of breakers associated with a BAAH design improves flexibility and reliability, but is also more costly than other substation configurations that were previously considered standard.[26] So the selection of a station configuration reflects a balance of cost and reliability along with other considerations, such as space requirements.

21. PG&E now states that its preferred bus configuration for "large and critical" substations is BAAH. PG&E further states that its current policy employs a BAAH configuration primarily for 230 kV and 500 kV busses, and critical 115 kV

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[25] How the TAC is borne by residential consumers is in practice difficult to estimate with accuracy due to California's tiered residential rate structure.

[26] Other configurations include Double-Bus-Single-Breaker, Ring Bus, Main/Auxiliary Bus, and possibly the lack of any common bus structure.

busses.[27] This change represents a significant shift in design preferences since the formation of the CAISO, and was undertaken with no policy input from the parties responsible for bearing the additional costs. In one case, PG&E cites as its justification a study performed by equipment supplier ABB comparing the reliability of one specific configuration (single bus) with a BAAH configuration.[28] However, PG&E has provided no technical or economic justification for its decision to establish a BAAH as a preferred bus configuration for "large and critical" substations. Nor did it provide opportunity for stakeholder input.

22. The extent to which the BAAH is used is unclear since PG&E does not provide significant information to stakeholders at this time, but the cumulative impacts could be significant if the practice is common. And even when PG&E does present the design configuration for a new electric station to the CAISO stakeholder process, it does not provide any justification for why the design is necessary. For example, in the CAISO 2016-2017 TPP, PG&E proposed using a 115 kV BAAH design for two new 115 kV customer interconnections with a 115 kV network upgrade cost of $190 million.[29] It gave no justification as to why these stations were deemed critical or whether the redundancy of a BAAH design was justified in light of the level of redundancy being proposed by the customer.[30] While that particular instance did go through the CAISO TPP, many others, which may be almost as expensive, have not.

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[27] TO18 Ex. 9 at 47:3-12.

[28] *Id.* at 47 n.18.

[29] The total cost including both upstream capacity upgrades and customer funded interconnection facilities is estimated at $228 million. Pac. Gas & Elec. Co., PG&E's 2016 Request Window Proposals: CAISO 2016/2017 Transmission Planning Process 11 (Sept. 22, 2016), http://www.caiso.com/Documents/PG_EPresentation-2016-2017TransmissionPlanningProcess.pdf.

[30] *Id*. at 11-13.

23. In addition to new substation installations, PG&E also rebuilds existing substations to a BAAH configuration. Under MWC 94 (Electric Transmission Reliability), PG&E forecasts a capital expenditure of $158 million in the Bus Reliability and Upgrade program.[31] This program includes converting existing substations using Double-Bus-Single Breaker or main-auxiliary bus configurations to a BAAH or ring bus configuration. The decision to invest in such a conversion is based upon PG&E's internal standards, which it characterizes as an economic test notwithstanding the fact that the test does not include a detailed economic analysis.[32] PG&E tests whether the station design meets PG&E's standards, whether overstressed breakers are present, the age of the equipment, and its ability to meet current seismic standards. If two of these factors are present, then PG&E will convert the substation.[33] At no point does it consider the cost/benefit tradeoffs to ratepayers of the BAAH compared to alternative configurations.

B. NERC Alert Program

24. The NERC Alert Program is driven by the October 7, 2010 NERC Recommendation to Industry for "Consideration of Actual Field Conditions in Determination of Facility Ratings."[34] This program is designed to ensure that the capabilities assigned to transmission facilities align with the actual field conditions.[35] For example, transmission circuit ratings are based upon the assumed height of transmission conductors above the ground. Minimum heights are necessary to ensure public safety by

[31] TO18 Ex. 9 at 45:11-12.

[32] *Id.* at 45:8.

[33] *Id.* at 44:32-45:8.

[34] *Id.* at 35-36.

[35] *Id.* at 36.

reducing the potential for contact with the conductor. As the power flow on the transmission circuit increases, the temperature of the conductors rises due to resistive losses. This temperature rise causes the conductors to elongate which reduces the height of the conductors above the ground. Therefore, the maximum loading allowed on a transmission line may be reduced if the height above ground is less than what was assumed in developing its rating. In response to this program, utilities surveyed the field conditions of their transmission facilities and developed a remediation plan. PG&E claims that its remediation plan generally involves increasing the height of the transmission line structures or the re-sagging conductor.[36]

25. In this situation, stakeholders could provide valuable insight on different options for remediation. For example, are reliability or system economics adversely impacted if a reduced conductor rating is simply accepted rather than initiating capital improvements? Alternatively, if the transmission facility is located in an area of system constraints, should the installation of higher capacity conductors be considered when developing a remediation plan?

26. The development of the individual remediation plan for a circuit has a direct nexus with the capacity planning that occurs within the CAISO TPP, yet there is no stakeholder involvement. For example, in Southern California Edison Company's (SCE) development of a similar program, Transmission Line Rating Remediation (TLRR), SCE decided to increase the conductor capacity on its 230 kV transmission circuits in the Big Creek corridor, the Magunden-Vestal No. 1 and No. 2 230 kV lines, and the Rector-

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[36] *Id.* at 36 n.15.

Vestal No. 1 and No. 2 230 kV lines.[37] Due to capacity constraints on these transmission lines, SCE initially submitted a proposal through the CAISO Request Window to install Thyristor Controlled Series Capacitors (TCSCs) at a cost of about $135 million.[38] These devices would have allowed more efficient use of the existing transmission line capacity. The CAISO did not approve the project following the initial submittal. Subsequent to this proposal, SCE identified and approved through its internal processes an alternate project whose primary purpose was to improve the line ground clearances under their TLRR program. Within that project, SCE chose to replace the conductors with higher capacity wire. With increased conductor capacity in place, the overall capacity of the corridor could be increased through an additional investment of $6 million over the conductor replacement cost. This allowed SCE to withdraw its $135 million project proposal in the next TPP cycle, and submit instead a project costing only $6 million to address some remaining minor limitations.[39] Stakeholders had no information or input as to whether it was better to expand the ground clearance work, install the $135 million upgrade, or do neither. Nor was there an opportunity for the competitive process to validate whether there was an even better solution to increase the corridor capacity.

27. These results highlight the linkage between "maintenance" related capital projects and capacity projects vetted in the CAISO TPP. SCE has been able to increase the size of the conductor as part of a "maintenance" activity, and therefore eliminate a

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[37] S. Cal. Edison Co., Big Creek Corridor Rating Increase (Sept. 21-22, 2016), http://www.caiso.com/Documents/SCEPresenation-2016-2017TransmissionPlanningProcess.pdf.

[38] S. Cal. Edison Co., Big Creek Corridor TCSC 5 (Sept. 22, 2015), http://www.caiso.com/Documents/PresentationPTOProposedMitigationSolutions_Sep22_2015.pdf.

[39] *Id.* at 1-11.

major capital expenditure in the CAISO TPP. It is important that an incremental approach to compliance not overlook big-picture considerations.

C. Electric Substation Equipment Replacement

28. PG&E's Electric Substation Asset Management (ESAM) program includes end-of-life replacement for various substation equipment such as circuit breakers (MWC 64), transformers (MWC 68), series capacitors, synchronous condensers, and air switches (MWC 66).[40] These MWCs reflect $307 million of PG&E's 2016-2017 capital expenditure forecast.[41] Such end-of-life replacement decisions include not only when such equipment should be replaced, but also the capacity of the replacement equipment. Those decisions currently do not go through any transmission planning process where stakeholders would have an opportunity to comment on both the timing and capacity issues.

D. Risk Informed Budget Allocation (RIBA)

29. In PG&E's Risk Informed Budget Allocation (RIBA) process, each project is assigned a score based on its potential to reduce risk exposure and increase operational efficiency.[42] The factors considered in the RIBA process are "Public Safety and Compliance, Reliability and Environment."[43] Each project receives an aggregate score that accounts for the above factors, and the list of projects is prioritized to meet the forecasted budget.[44] While this management process is an important tool in determining which projects to fund, it is also an important opportunity for stakeholder input. For

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[40] TO18 Ex. 9 at 27:8-10.

[41] Table PGE-9-1.

[42] TO18 Ex. 9 at 2:3-14.

[43] *Id.* at 2:7-12. It is unclear from PG&E's description whether there are two, three, or four factors in scoring a proposed project.

[44] *Id.* at 2:12-14.

example, how does PG&E value reliability or public safety in its scoring and how does the total budget available track its requests to FERC for funding?

E. Two Project-Specific Examples Of The Need For A Stakeholder Process Consistent With The Order No. 890 Principles

30. *Sobrante: Add Two Bus Sectionalizing 115 kV Breakers.* The Sobrante 115 kV bus is currently a Double-Bus-Single Breaker configuration. Due to concerns about overlapping bus outages, PG&E has proposed to install bus sectionalizing breakers, replace twelve deteriorated Oil Circuit Breakers, and perform other associated work under its System Reliability and Automation program at a projected cost of $15.2 million.[45] This project also proposes upgrades to improve the system reliability beyond the level required by NERC standards.[46] The improvement in reliability may well justify this project, but it is difficult to discern in isolation and without a robust Order 890-compliant process.[47] For example, how many other PG&E substations are similarly situated and how was Sobrante selected for this upgrade? PG&E also notes that these upgrades avoid other potential system capacity improvements,[48] the type of work that would be submitted to the CAISO and receive stakeholder review.

31. *El Cerrito G: 11kV Bus Upgrade Phase 1 Project.* In this project PG&E proposes to rebuild the El Cerrito G 115kV switchyard to a BAAH arrangement at a cost

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[45] *Id.* at 48:4-49:23.

[46] Consideration of an overlapping bus outage is beyond the requirements of the NERC Planning Standards and does not require a corrective action plan for compliance. If this project was required by the Planning Standards, the project proposal would need to be submitted through the CAISO TPP process where it would have received stakeholder review.

[47] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 Fed. Reg. 61,511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[48] TO18 Ex. 9 at 48:23-27.

of $18.7 million so that PG&E can more easily replace existing distribution transformers.[49] PG&E asserts that "[t]he 115 kV is an older design and does not provide the level of reliability needed today."[50] PG&E describes a number of issues with its distribution system in the area and its proposal to upgrade both the transmission and distribution facilities.[51] Based on this brief description, it is unclear whether the reliability deficiency is primarily due to inadequate distribution facilities or whether the 115 kV facilities are also inadequate. Also, it is not clear how PG&E may have applied its "economic test" to this facility in deciding to convert it to a BAAH arrangement. Lastly, it is not clear what standard PG&E applies in determining the level of reliability needed today.

CONCLUSION

32. The majority of the capital expenditures in PG&E's TO18 2016-2017 capital forecast are not subject to any stakeholder review prior to PG&E's submission to FERC for cost recovery. But stakeholders, who may be the beneficiaries of the projects and will bear the costs, could provide meaningful input into these projects, particularly in the art of balancing reliability and cost. In addition, these programs overlap with capacity planning and compliance with the NERC Transmission System Planning Performance Requirements[52] and should thus be subject to a stakeholder process such as the CAISO TPP.

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[49] *Id.* at 49:24-51:8.

[50] *Id.* at 50:1-2.

[51] *Id.* at 50:3-17.

[52] Transmission Planning Reliability Standards, Order No. 786, 78 Fed. Reg. 63,036 (Oct. 23, 2013), 145 FERC ¶ 61,051 (2013) (NERC Standard TPL-001-4).

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief. Executed in Discovery Bay, California, on this 1st day of February, 2017.

Robert Jenkins