CALIFORNIA PUBLIC UTILITIES COMMISSION

PETITION 21-07-012

PUBLIC TESTIMONY OF CITY AND COUNTY OF SAN FRANCISCO EXPERTS

April 10, 2023

TABLE OF CONTENTS

(Reports and Appendices not included)

Docket:	P.21-07-012
Exhibit No.:	__________
Date Served:	April 10, 2023
ALJ:	R. Lirag
Witnesses:	Nelson Bacalao

PUBLIC VERSION – Redacted Pursuant to PG&E Non-Disclosure Agreement

PREPARED

DIRECT TESTIMONY

OF

NELSON BACALAO

ON BEHALF OF

THE CITY AND COUNTY OF SAN FRANCISCO

APRIL 10, 2023

TABLE OF CONTENTS

Appendices

I. INTRODUCTION AND SUMMARY

This testimony provides a description of the inventory that the City and County of San Francisco (the "City" or "San Francisco") intends to acquire. The inventory includes all the Pacific Gas & Electric Company (PG&E) electric transmission and distribution system assets located in the City and certain assets in San Mateo County.

The testimony provides a Reproduction Cost New (RCN) value of 10 billion 428 million dollars ($10.428 billion) for the PG&E system that the City seeks to acquire and explains the basis for this valuation.

The testimony has four purposes: 1) To provide an inventory of the electric assets the City seeks to value; 2) To provide a Reproduction Cost New (RCN) of the electrical assets; 3) To provide the age of asset types in the electric system; 4) To provide a high-level opinion on the condition of the assets. The testimony is based on a two-volume report produced for this proceeding. "San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 10, 2023), Volume I: Executive Summary, Distribution Inventory and RCN (attached as Appendix I) and Volume II: Transmission Inventory and RCN (attached as Appendix II). This report is based on data, calculations, and assumption in a set of workpapers (*see* Attachment A to Appendix IV).

QUESTIONS AND ANSWERS

EXPERIENCE AND QUALIFICATIONS

Q1. Please state your name, business affiliation, and title.

A1. My name is Nelson Bacalao. My business address is 5980 W Sam Houston Pkwy N, Houston, TX 77041.

Q2. By whom are you employed and in what capacity?

A2. I am a Principal Consultant at Siemens Power Technologies International ("Siemens PTI"), a division of Siemens Industry Inc.

Q3. Please summarize your education and your experience relevant to your testimony.

A3. I hold a Ph. D. in Electrical Engineering from the University of British Columbia, Vancouver, BC, Canada, earned in 1987. I hold a Master's Degree in Electrical Engineering from Rensselaer Polytechnic Institute in Troy, NY, earned in 1980. I hold a Degree in Electrical Engineering from Universidad Simon Bolivar in Caracas, Venezuela, earned in 1979.

My professional experience covers technical and strategic consulting services to utilities, governments, regulators, independent project developers, and the financial community, in domestic as well as international assignments. My work has centered on power system planning and in particular transmission and distribution planning. I have conducted multiple transmission planning studies and integrated distribution planning studies.

Of particular relevance to my testimony is my experience in a proceeding similar to this one. The Sacramento Municipal Utility District (SMUD) conducted a feasibility assessment of the annexation of the cities of West Sacramento, Woodland and Davis in Yolo County. As part of the assessment in 2004 to 2005, I managed and actively participated in creating an inventory of the transmission and distribution assets to be acquired. I also estimated the Reproduction Cost New (RCN) of these assets and produced a severance plan. I am the manager and lead contributor to the technical feasibility assessment of the proposed South San Joaquin Irrigation District (SSJID)'s electric distribution municipalization. The SSJID study required conducting a detailed distribution and transmission system inventory and estimation of the corresponding RCN. In addition, I developed the severance plan and its costs. I started working with SSJID when the project started in 2004 and the project continues to this day. The scope of this work is very similar to the SMUD project.

My education and experience are also discussed in my resume, a copy of which is attached as Appendix III.

Q4. Have you appeared before the California Public Utilities Commission (CPUC) or other public utility commissions?

A4. Yes. I participated and made presentations to the CPUC on the 1997-1999 PG&E Capital Expenditure Audit; a study conducted in 2002 by my previous employer Stone & Webster Inc.

I presented testimony before the Puerto Rico Energy Bureau on the First Integrated Resource Plan for the Puerto Rico Electric Power Authority (2015) and the 2018 Puerto Rico Electric Power Authority Integrated Resource Plan, Case Nos. CEPR-AP-2015-0002 and CEPR-AP-2018-0001, on behalf of the Puerto Rico Electric Power Authority ("PREPA"). I also testified before the Indiana Utility Regulatory Commission, IURC Case No. 45564, on behalf of CenterPoint Energy to support CenterPoint Indiana South's 2019/2020 Integrated Resource Plan ("2019/2020 IRP").

Q5. On whose behalf are you submitting testimony?

A5. I am submitting testimony on behalf of the City and County of San Francisco ("San Francisco" or the "City").

Q6. What is your role in this proceeding?

A6. I am lead investigator on the consulting team hired by the City, led by Advisian with Siemens PTI as a subcontractor, to produce an Inventory and RCN of the electrical assets that the City intends to acquire. I am the principal author of the two-volume report in Appendix I and II. I have been a consultant to the City on an engineering assessment of municipalization of the service in the City since 2019.

II. INVENTORY OF ELECTRICAL ASSETS

Q7. Please describe the electric assets in the inventory.

A7. The inventory includes all of PG&E's electric transmission and distribution system assets located in the City, and certain assets at, and emanating from, the Martin Substation in San Mateo County.

The PG&E bulk power transmission sources supplying the City and County of San Francisco currently include two 230 kilovolt (kV) PG&E lines and six 115 kV PG&E lines connecting at Martin Substation, just south of San Francisco. The 230 and 115 kV transmission lines in San Francisco are almost entirely underground and deliver power to an interconnected grid providing service to six major transmission-fed distribution substations, in the City. This power is delivered into San Francisco via two 230 kV lines from Martin Substation to Embarcadero Substation and six 115 kV lines from Martin Substation interconnecting with Hunters Point, Bayshore, Potrero and Larkin Substations. Mission Substation, another major downtown substation, is interconnected at 115 kV with Larkin, Hunters Point, and Potrero Substations. There is also a 230 kV submarine connection between Embarcadero and Potrero Substations.[1]

Seven transmission-to-distribution substations supply the City's distribution system: six located in the City (Potrero, Hunters Point, Bayshore, Larkin, Mission, and Embarcadero) and one located outside the City in San Mateo County (Martin). The inventory for these substations includes all 230 kV assets inside the City, namely Embarcadero 230 kV Gas Insulated Substation (GIS) and Potrero 230 kV GIS, as well as 230/115 kV transformers in the City. These Transmission substations contain Distribution Voltage-Level Assets which include all medium voltage (MV) (34.5 kV, 12 kV or 4.16 kV) assets located within the transmission substations. This also includes transformers with high-side voltages of either 230 kV or 115 kV that step down to MV, such as 115/12 kV transformers and 230/34.5 kV transformers. The 115 kV switchyards or GIS at these substations are also included in the inventory.

There are 23 MV PG&E distribution substations in San Francisco that do not have a high voltage (115 kV and above) transmission supply. These substations are typically supplied from 12 kV express circuits, called tie-lines by PG&E, and are the source for additional 12 kV and 4.16 kV radial distribution circuits in San Francisco.

PG&E provides distribution supply in San Francisco from radial and network circuits operating at 34.5 kV, 12 kV, or 4.16 kV. PG&E operates the following distribution systems in San Francisco:

- 34.5 kV radial system
- 12 kV radial system
- 4.16 kV radial system
- 12 kV tie lines (express circuit) system

[1] Note, the City also receives power via the Transbay Cable (TBC), a High Voltage Direct Current submarine cable. It supplies electricity to the City by linking PG&E's 230 kV substation in Pittsburgh (Contra Costa County) to PG&E's 230 kV Potrero substation in the City. The TBC is owned by NextEra Energy, Inc. (through subsidiaries), and is not in the inventory because PG&E does not own it.

- 34.5 kV spot network system
- 12 kV grid and spot network systems

The downtown area of San Francisco near Market Street is served by a Low Voltage (LV) network system. In a network distribution system, the distribution circuits operate in parallel, unlike the typical radial distribution circuits, so each customer is served from more than one source, having high reliability compared to radial systems.

The list of electrical assets included in the Inventory is in an Excel file, "SanFrancisco_All_ Assets.xlsx," in Attachment B to Appendix IV.

Q8. Does this list of electrical assets identify every asset in the inventory?

A8. No. The inventory lists hundreds of thousands of distinct assets based on the information received from PG&E. PG&E did not list every single item that makes up the electric system that San Francisco seeks to acquire. The inventory lists the major equipment at substations,[2] and all the other items that are not expressly identified are accounted for in the "Substation Layout." This captures all the equipment and materials used at the substations (which is what the City intends to acquire). [3] For the transmission lines,[4] the inventory identifies the major equipment and the unit cost for these items includes the cost of all the related equipment. For transmission lines, the related equipment includes, but is not limited to, the manholes, vaults, pipes, and supporting equipment, such as pumps and cathodic protection systems.[5]

Q9. From what sources was the inventory compiled?

[2] Attachment B to Appendix IV, San Francisco_All_ Assets.xlsx ("Trans. Substation Assets" tab and "Dist. Substation Assets" tab).

[3] Appendix I, p. 84 (discussing Substation Layout(and Appendix II, p. 43 (discussing Substation Layout).

[4] Attachment B to Appendix IV, SanFrancisco_All_ Assets.xlsx ("Transmission Lines Asset" tab).

[5] Appendix II, p. 39, fn.18.

A9. The inventory is based on PG&E's responses to data requests, including geodatabases for distribution assets,[6] and one for transmission assets.[7] PG&E also provided excel spreadsheets that listed inventories for Secondary Meters,[8] Streetlights,[9] Spare Parts, [10] Fiber Optic Cables,[11] and Substations.[12] Analysis of the single line drawings (SLDs) that PG&E provided for substations[13], and visual inspections of substations and cables were also carried out to complete the inventory.

Q10. Describe the process for extracting data from the geodatabases?

A10. For most of the distribution system assets, the geodatabase file contains a "database" with geographic coordinates, locations, and detailed information on assets. The geodatabase has a "Table of contents" that shows the "components" or "layers" defined by PG&E. To analyze and view the data in the geodatabase, the layers can be turned on and off to improve the visibility of the data

My team used the ArcMap software from Esri which enables Excel exports for each "layer;" a layer represents a single component or asset class of the distribution system. My team used this procedure to extract the information for the distribution asset inventory into excel workpapers. My team developed nineteen asset types from the geodatabase. These nineteen asset types are the following:

1) Primary Overhead Conductors;

2) Support Structures;

3) Primary Underground Conductors;

4) Conduit Systems;

5) Distribution Transformers;

[6] Attachment C to Appendix IV (ccsf_eddata.gdb.zip).

[7] Attachment S to Appendix IV (ccsf_etdata.gdb.zip).

[8] Attachment E to Appendix IV (PGE000066831.xlsx).

[9] Attachment F to Appendix IV (PGE000000732-A.xlsx).

[10] Attachment O to Appendix IV (PGE000073872.xlsx).

[11] Attachment P to Appendix IV (PGE000082703-Rev.xlsx).

[12] Attachment H to Appendix IV (PGE000073870).

[13] Attachment D to Appendix IV (PGE000073824 to PGE000073867).

6) Secondary Overhead Conductors;
7) Secondary Underground Conductors;
8) Capacitor Banks;
9) Voltage Regulators;
10) Switches;
11) Fuses;
12) Primary Risers;
13) Secondary Risers;
14) Network Protectors;
15) Primary Meters;
16) Smart Meter Network Devices;
17) Padmount Structures;
18) Subsurface Structures; and
19) Reclosers and Interrupters.

For each asset types, the key characteristics are the following:

- Overhead/Padmount/Underground equipment: These represent the type and location of the equipment installation.
- Voltage level: The PG&E system contains voltage levels from 2.4 kV to 34.5 kV. The Consulting Team grouped certain types of equipment into voltage classes: 5 kV Class for 2.4 and 4.16 kV, 15 kV Class for 6.9 and 12.47 kV, and 35 kV Class for 34.5 kV.
- Rating: This is the electrical rating of the equipment expressed in kVA, MVA, Amps, or Watts, depending on the type of equipment.
- Number of phases: Engineers design electrical equipment for a certain number of phases, which can be single phase, two phases, and three phases, but some combination of single-phase units also can be used. One example of this is the transformer banks, e.g., 2x25 kVA & 1x15

kVA, which means a transformer bank with two units of 25 kVA and a single unit of 15 kVA to feed a three-phase load or multiple single-phase loads.

- Dimensions: Some components, such as poles or vaults, have dimensions. For example, my team can extract height and class for poles and identify the typical dimensions of PG&E's vaults in the City.

My team used the same process for the transmission lines -- extracting data from the transmission geodatabase and creating an excel workpaper.[14] The geodatabase includes information on all 230 kV and 115 kV underground transmission lines (cables), the route and length of conductor, and the conductor type.

Q11. Are there any other asset types in the inventory that were not in the geodatabases?

A11. Yes. PG&E provided information on secondary meters, streetlights, fiber optic cables, and spare parts in Excel Spreadsheets. Based on this data, my team also created workpapers for these four asset types. In total, twenty-three asset types were created.

Q12. What process was used for the substations?

A12. PG&E provided an excel spreadsheet listing the major equipment at the Medium Voltage Substations and the seven transmission-to-distribution substations. In addition, PG&E provided SLDs for each substation which I used to confirm the inventory for the substations. I carried out site inspections at transmission-to-distribution substations in December 2022, and at a sampling of distribution substations in January 2023, to confirm my understanding of the system and the accuracy of the data that PG&E provided. During the inspections, [redacted]

---

[14] Attachment A to Appendix IV (workpaper "Lines_Unit_Cost&RCN_03_23.xlsx").

[15] Appendix II, pp. 12, 17, 21, 29.

[redacted]

During the inspections we collected information on the ratings of the main power transformers, which change according to the cooling modes (ONAN, ONAF1, ONAF2).

Q13. Did you add any other assets to the inventory?

A13. Yes, I added about .5 miles of overhead cables. Outside of the substation, I noted two small overhead cable sections connected to the Hunters Point substation [redacted] These are Hunters Point (HP 4), with about 0.2 miles of overhead cables before transitioning to underground, and Hunters Point to Mission (PX 1), with about 0.3 miles of overhead cables before transitioning to underground.

Q14. Is there a cut-off date for placing electrical assets in the inventory?

A14. The City sought a list of assets from PG&E as of July 27, 2021, the date the City filed the petition in this proceeding. PG&E only started providing records in response to data requests after the scoping memo was issued on June 22, 2022. As part of PG&E's general objections, PG&E stated "attempting to produce the responsive information as of July 27, 2021 would be unduly burdensome."[16] Because of this, the inventory may include equipment installed after July 27, 2021. Given the hundreds of thousands of entries, it would be extremely burdensome for me to identify this equipment in PG&E's databases. Consequently, the inventory includes all the equipment identified by PG&E in its Geodatabases and spreadsheets.

[16] Attachment G to Appendix IV (Data Response PG&E to CCSF Data Request Set 2 (September 9, 2022) Q01-02).

Q15. Does the inventory include any other assets?

A15. It does. PG&E provided a list of the spare inventory that is available to use for the system in the City. This list is included as part of the inventory.[17]

The inventory also includes the communication equipment associated with PG&E's electrical equipment in the City including but not limited, to communication assets in substations, fiber-optic cable,[18] repeaters, AMI communication, SCADA systems, among others.

Q16. Does the inventory list include everything the city seeks to value?

A16. No. This inventory includes the electric assets San Francisco seeks to value as described. This list does not include the real property that the City seeks to value, including land and buildings where the substations in the asset inventory are located. This will be valued by a real estate appraiser.

Q17. You refer to "my team" in your discussion of the inventory. Did you prepare the inventory?

A17. Yes, I prepared the inventory, with assistance from my colleagues, Jorge Matheus, Ismail Sahin, Guillermo Sovero-Ancheyta, and Soha Metwally, who worked under my direction and supervision. These colleagues also worked on preparing the RCN which is discussed next. Where appropriate, I refer to this as work conducted by "the team."

III. VALUING THE INVENTORY USING A REPRODUCTION COST NEW CALCULATION.

Q18. Define reproduction cost new ("RCN")?

A18. RCN is the cost to construct a duplicate of PG&E's Distribution and Transmission system as identified in the electrical asset inventory (collectively "PG&E's system") and in present day costs. I consistently used 2022 dollars in my analysis to ensure that the assets were valued with the same reference.

[17] Attachment B to Appendix IV (five tabs listing Spare Parts).

[18] Attachment B to Appendix IV (FiberOptic tab).

Q19. What is the RCN for PG&E system that the City intends to acquire?

A19. The RCN estimated by the consulting team for the entire City power system is $10.428 billion, divided into $7.222 billion for distribution assets (69% of the total)[19] and $3.207 billion (31% of total) for transmission assets.

A. DISTRIBUTION SYSTEM RCN

Q20. Taking the distribution system first, please summarize your results.

The RCN of all distribution assets is $7.222 billion and includes:

- Distribution overhead lines, ranging from 4.16 kV to 12 kV.
- Distribution underground cables, ranging from 4.16 kV to 34.5 kV.
- Low Voltage Secondary conductor ranging from 120 V to 480 V.
- All supporting equipment for the overhead and underground lines, such as poles, vaults, switches, fuses, and meters – hundreds of thousands of items.
- Distribution substation equipment across 23 substations.

The table below summarizes the medium and low voltage assets by main function followed by the assets in the MV Substations detailing transformers and switchgear.

In this table we include a 10% contingency and a 25% Owner Costs. The contingency is intended to capture added cost incurred during construction beyond those included in our calculations as well as any imprecisions in the inventory. The Owner's Costs is used in RCN determinations both for transmission and distribution and it is intended to capture back-office costs not directly included in the turnkey cost of the projects and include but not limited to general and administrative costs (G&A), regulatory, legal and compliance costs, owner provided fleet costs, owner's project management and supervision. In this table and other tables in my testimony, values are rounded to the nearest millions which may result in rounding error when values are added. The workpapers contain exact values.

[19] Note, this RCN does not include distribution assets in the seven transmission-to-distribution substations. Those are included as part of the analysis of the Transmission RCN. These values are rounded to the nearest million and adding them to the Transmission RCN results in a rounding error.

Table: Distribution RCN Summary[20]

Network Assets (MV/LV)	Total M $
Feeders	[redacted]
Poles	[redacted]
Duct Banks	[redacted]
Distribution Transformers	[redacted]
Switches, Reclosers, Interrupters and Others	[redacted]
Secondary System and Services	[redacted]
Meters	[redacted]
Street Lights	[redacted]
Distribution Subtotal	[redacted]
Owner Costs - 25%	[redacted]
Contingency 10%	[redacted]
Distribution Total	[redacted]
MV/MV Substations	**Totals M $**
Transformers 12/4.16 kV	[redacted]
Switchgear and other	[redacted]
12 kV Breakers, Switches & Others	[redacted]
4.16 kV Breakers, Switches & Others	[redacted]
Subtotal	[redacted]
Substation Layout (15%)	[redacted]
Owner's costs (25 %)	[redacted]
Contingency (10 %)	[redacted]
Total	[redacted]
Network Assets (MV/LV)	**Totals M $**
Distribution Network MV and LV	[redacted]
Distribution MV/MV Substations	[redacted]
Total	**7,222**

Q21. What process did you use for calculating the RCN?

A21. I calculated the RCN of the distribution assets by separating the distribution system into two major parts: 1) the distribution system connecting substations and customers, and 2) the 23 MV substations. The methodology for calculating the two major parts differed.

Q22. First, please explain how you developed the RCN for distribution assets other than those in the MV substations.

[20] These values are rounded to the nearest million and adding them may result in a rounding error.

A22. After exporting all the distribution electrical asset data into workpapers, my team had to sort through hundreds of thousands of records. Given the vast number of unique equipment with various voltage classes, current ratings, configurations, and other attributes, my team grouped similar types of equipment for valuation purposes. Furthermore, the electrical equipment requires supporting equipment that may not be expressly listed in the geodatabase; however, this support equipment provides a function to the distribution system and carries value. To determine costs per asset type, I categorized equipment by "Construction Units." A Construction Unit represents a combination of elements that provide a specific function in the electrical distribution system. For example, a utility pole's function is a support structure for conductors and transformers to deliver power from point A to point B. The elements comprising a utility pole could include the pole itself, the material for the concrete base, clamps, grounding conductor, and the labor required to dig the hole, set the pole, and pour the concrete. To determine a total cost, the other important element is the quantity of each Construction Unit. The distribution workpapers catalog all of the Construction Units and their quantities.[21] Section 3 of Volume 1 of my report describes the main Construction Units for twenty-three asset types.[22]

Once the Construction Units and quantities were established, an adjusted unit cost is calculated for every Construction Unit. The calculation starts from the base Construction Unit costs retrieved from RSMeans. RSMeans is the most comprehensive cost estimating database for the construction industry that is available. The RSMeans cost estimating database is published by Gordian, is available online and it is updated quarterly.[23] I used data from the third quarter of 2022. These unit prices are cost estimates per construction task, including labor, material, and equipment costs for a specific location, San Francisco. RSMeans adjusts these values to include the contractor overhead and profits, which varies by asset type.

---

[21] Attachment A to Appendix IV (workpapers in Distribution Folder).

[22] Appendix I, Sections 3.2 – 3.25.

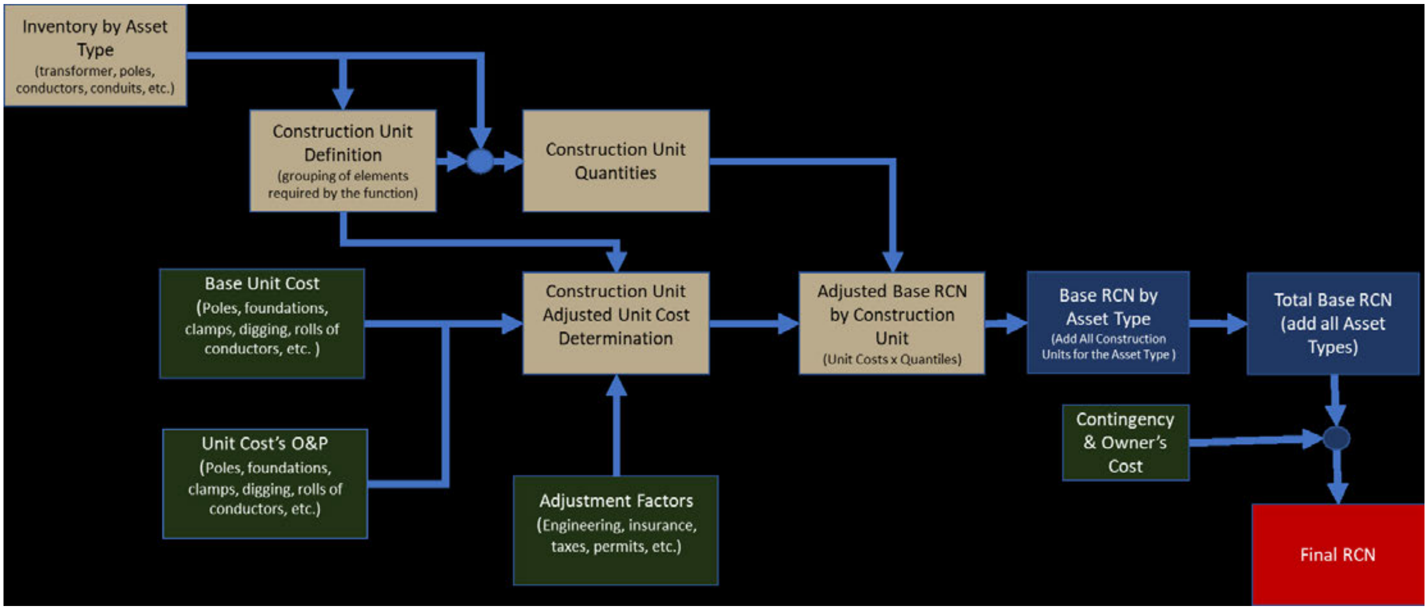
[23] RSMeans cost estimating database is available by subscription https://www.rsmeansonline.com/ [Last Visited 4/6/2023]).

The values from RSMeans are then adjusted, because this cost only includes the price up to the contractor level, including Overhead and Profits. An accurate valuation must factor in costs of other items, such as engineering, construction management, job conditions, local taxes, permits and insurance. The Consulting Team adds these costs by adjusting the base cost with specific factors to consider the particularities of a given job. RSMeans dictates the adjustment factors for Engineering, Construction Management, Permits, and Insurance based on project location. The Consulting Team used RSMeans adjustment factors in the analysis. Those include an additional 4.1% for Engineering; 4.5% for Construction Management, 0.5% for Permits, and 0.44% for Insurance. Another adjustment is for sales tax, which is 8.625% in San Francisco.

RSMeans also has an adjustment for job conditions, which I applied. In this analysis, the job conditions account for the conditions under which the job is carried out. For almost all assets, the job conditions in the City are considered more difficult than average (5% adjustment). However, for underground construction, the Job Conditions for the City were considered much more difficult than average (35% adjustment) because the construction could involve: closing roads in a busy city, creating disruption that may require overtime, working overnight during low traffic hours, creating trenches for construction periodically, and/or installing underground facilities in streets containing other utilities.

The adjusted unit costs obtained were then used to calculate the asset RCN. The total adjusted RCN of a specific Construction Unit equals the quantities included in the inventory multiplied by the estimated Construction Unit price.

I then added a 10% Contingency. The 10% contingency is appropriate to use in this assessment because the inventory has a high level of accuracy and completeness based on the extensive data from PG&E, inspections, and my experience with valuing power systems. I then further added a 25% Owner's Cost to the entire adjusted base RCN to determine the final RCN. This flow chart shows the process:



Utilizing this methodology, my team and I analyze all the asset types in the inventory utilizing Construction Units and unit costs to determine RCN for the asset type. The individual RCNs are then aggregated for each asset type to compute the total RCN for the distribution system.

Q23. Please explain how you calculated the RCN for the substations.

A23. The RCN of the substations is determined using the totals of each major component in the substation shown in the table. This includes the main transformers (12/4.16 kV) as well as the breakers, switches, and other components. Under other components, we include measuring transformers, capacitors, reactors and auxiliary service transformers.

For each component of the substation a unit cost is determined using RSMeans. The same adjustment factors used for the other distribution system assets are applied to the unit costs. However, a "Substation Layout" cost of 15% is added to account for other costs in addition to the major components listed in the substation inventory. These include site preparation, fences, ground grid, cabling, protection, and control and communications, among others. Based on my experience and professional judgment 15% is appropriate because the bulk of the value of the substation is in the major components that are expressly included and the 15% adder is sufficient to cover these additional items. A contingency of 10% and an Owner's Cost allowance of 25% are also calculated and summed for a total RCN.

Based on these calculations, the twenty-three MV Substations' RCN is estimated at $126 million. This number results from multiplying the quantities of each major component times the unit costs determined using RSMeans and adding the 15% "Substation Layout", 25% Owner's Costs, and 10% contingency. The workpaper "San_Francisco_MV_MV_Substations_Assets_Estimation_Totals_2022_RCN_02_23" provides the details of the calculation and the workpaper "SF_Substation_Unit_Costs_02_23.xlsx" contains the unit costs used for the analysis. [24]

The RCN shown does not include the cost of land or any buildings, beyond the metallic enclosures of the metal-clad switchgear. The land and buildings are not valued in my analysis, which is addressed by a different expert.

B. TRANSMISSION SYSTEM RCN

Q24. What is the total transmission RCN?

A24. The transmission assets RCN is $3.207 billion.

Q.25 What process did you use to calculate the transmission system RCN?

A25. I calculated the RCN of the Transmission system in two major parts: 1) the transmission lines and 2) seven transmission-to-distribution substations.

Q26. How did you calculate the RCN for the transmission lines?

A26. I used the transmission line inventory to calculate the RCN for the 115 kV lines and 230 kV transmission lines. The unit cost for each cable is determined based on its voltage class, length and type (underground or submarine). The unit cost includes the cost of manholes, vaults, pipes, and supporting equipment, such as pumps and cathodic protection systems. The cable lengths were provided by PG&E. I also estimated the number and type of special crossings; these are priced separately. Special crossings include highways and submarine cable landings.

My team and I used the Transmission Infrastructure Cost Estimating Guide_ 2021 Update (EPRI Guide) to estimate transmission cable unit costs. This guide is the best available source for

[24] See Attachment A to Appendix IV.

calculating underground and submarine transmission cable costs. The unit cost is inclusive of all construction aspects for a turnkey project. The EPRI Guide provides unit costs for transmission cables per mile for land-based and submarine cables. The EPRI Guide considers voltage class and provides costs for special crossings. The EPRI Guide provides a regional adjustment factor for the "Pacific West" that accounts for "Regional Labor and Labor Posture" and is used in the calculation. In addition, we converted values provided in 2021 dollars to 2022 dollars.

A contingency of 10% is added to the estimate as well as 25% to cover Owner's Costs. I use the same Owner's Costs, as described above, for all the RCN determinations. The 10% contingency is intended to capture added cost incurred during construction beyond those already included in the unit cost, as well as imprecisions in the inventory, such as the small overhead sections of lines connecting to Hunters Point, which is not otherwise valued. Based on my experience valuing power systems, the extensive data that PG&E provided, and our inspections, I believe the inventory (of both transmission lines and substations) has a high level of accuracy and completeness, and therefore, 10% is an appropriate contingency factor.

The RCN that I calculated for the 115 kV transmission cables is $[redacted] including the contingency and Owner's Costs. The RCN for the 230 kV cables is $[redacted] including the contingency and Owner's Costs. The total RCN of the transmission cables is $[redacted] The workpaper provides details of the unit costs and RCN calculation for each transmission line.[25]

Q27. Please explain how you calculated the RCN for the seven transmission-to-distribution substations?

A27. To calculate the substation RCN, my team and I broke down the substations into component parts and assigned each a unit cost. I used multiple sources to identify the unit costs of the major components of the transmission substations. The sources include:

- 2021 PG&E Proposed Generator Interconnection Unit Cost Guide
- WECC Substation Capital Cost Calculator
- SDG&E Rule 21 Unit Cost Guide

[25] Attachment A to Appendix IV (workpaper "Lines_Unit_Cost&RCN_03_23.xlsx").

- MISO MTEP Cost Estimating Guide 2022
- RSMeans Electrical Data Cost 2022
- Transmission Infrastructure Cost Estimating Guide_ 2021 Update (EPRI Guide)
- Siemens Energy Costs for GIS substations[26]

It is typical to rely on RSMeans for distribution assets, but RSMeans does not cover all the required components of the high voltage transmission substations. Consequently, I consulted multiple sources as not all unit costs are found in a single source. These multiple sources show a range of unit costs, as unit costs are generally influenced by assumptions such as local costs and job conditions, size of the work (the smaller construction projects are more expensive due to less economies of scale), and actual construction costs that may or may not include balance of plant components.

I selected unit costs adjusted for California and San Francisco, based on information in the sources above as well as reasonable assumptions based on my engineering judgement and experience. The Consulting Team gave preference to PG&E costs in the Interconnection Unit Cost Guide. However, the PG&E published unit costs are intended to cover costs, overhead and construction contingencies for interconnection of generation, which has a smaller scope than building an entirely new substation and lacks the economies of scale in constructing an entire new substation, or replacing an entire electric line. Thus, PG&E's published unit cost may be too high and alternative sources are considered for each unit cost type. The Consulting Team applied its engineering judgement to determine the best source for each unit cost. For example, for the substation layout costs, we used EPRI's costs as more appropriate for building an entire new substation. With larger construction projects, the overheads and contingencies have a smaller effect on the unit costs as they are spread among a larger project and over a longer duration. The RCN intends to represent large system buildouts; therefore, the unit cost should be less than PG&E's costs for interconnection of generation. The workpaper "SF_Substation_Unit_Costs_02_23.xlsx" shows the unit cost for each asset and its source.[27]

[26] Citations for these sources are in Appendix II, page 42.

[27] *See* Attachment A to Appendix IV.

For each substation, the unit cost is inclusive of all construction aspects for a turnkey project. In addition, a Substation Layout Cost is added to cover costs not directly captured under the major equipment costs. The Substation Layout Costs include protection, control and communication, ground grid, cabling, fences, access roads, and site preparation. The costs are taken from the sources referenced above that are the most appropriate for the particular substation type and voltage and consider a typical substation layout. The actual Substation Layout costs considered in the RCN determinations include an adjustment based on the size of the substation compared to the typical layout. The major equipment costs in the inventory, together with the Substation Layout costs, captures all the equipment and materials used at the transmission substations (which is what the City intends to acquire).

A contingency of 10% is added to the estimate as well as 25% to cover Owner's Costs.

The total RCN for the seven transmission-to-distribution substations is approximately $[redacted].[28]

Q28. Does PG&E's project to upgrade the Larkin substation affect the RCN for Larkin?

A28. No. PG&E is upgrading the Larkin substation with new 12 kV equipment. Even though the calculated RCN provides the RCN for the currently used 12 kV assets, this RCN will remain valid after the upgrades are complete. The RCN remains valid because it considers the type of construction used in the upgrade (building enclosed switchgear), the same number of breakers, and provides the cost of the new equipment (which corresponds to what PG&E has already purchased).

Q29. Please describe the method for valuing the Martin substation.

A29. I used the same methodology for calculating the RCN of Martin as I used for the Transmission Substations located in the City. For the Martin substation, I calculated the RCN separately for two scenarios:

[28] Appendix II, Table 3-2 (the RCN for each transmission substation and the total RCN for all transmission substations is presented in the table, separated by voltage level, to represent the major equipment in substations).

1. Scenario 1: includes the 230/115 kV transformers, the entire 115 kV switchyard, the 115/60 kV transformer as well as 115/12 kV transformers and MV switchyard.

2. Scenario 2: includes the 230/115 kV transformers, the central section of Martin 115 kV as well as 115/12 kV transformers and MV switchyard. It does not include the 115/60 kV transformer.

The RCN, without contingency and Owner's Costs, is $[redacted] for Martin Scenario 1 and $[redacted] for Martin Scenario 2. The Martin 230 kV switchyard assets are not included in either Scenario because the City does not intend to purchase this asset; accordingly, these assets are not included our calculated RCN of assets the City will acquire. However, we calculated an RCN for the Martin 230 kV switchyard for informational purposes and to use for the comparison below of our calculated total Martin Substation RCN with PG&E's cost documentation for the Martin Substation.

My calculation of the total transmission substation RCN (Table 3-2 of Appendix II) and the total transmission RCN (Table 5-1 of Appendix II) uses Scenario 1 above, which reflects the City's maximum potential Martin substation asset acquisition.

Q30. Please describe the validation of your substation RCN calculations.

A30. As a check on the validity of our RCN calculations, we compared two of our substation RCN calculations to actual cost data provided by PG&E.

PG&E provided the final invoice for the 230/115 kV GIS at the Potrero substation.[29] This invoice reflected a total value of $[redacted] in 2018$, that represents approximately $[redacted] in 2022$. (2018$ are adjusted to 2022$ using the "Handy-Whitman Cost Trends of Electric Utility Construction – Pacific Region – Station Equipment Index, table E6"). Comparing this value with the RCN of $[redacted] calculated for the 230/115 kV GIS including the contingency, there is a difference of only [redacted]%. This confirms the validity of this RCN calculation. Note that no Owner's Costs are included in either number, as this would be in addition to the invoice.

[29] Attachment Y to Appendix IV (PGE000103576).

PG&E also provided the "2021 Plant in Service" cost of the Martin substation.[30] This information reflected a Plant in Service cost of $[redacted] in nominal dollars. This value can be converted to 2022 dollars using the Handy-Whitman index of Public Utility Construction – Pacific Region – Station Equipment Index, using an average installation date for the substation equipment of 2012. These calculations resulted in $[redacted] in 2022$, which is only [redacted]% higher than our RCN. This confirms the validity of this RCN calculation.

Q31. Is this the only validation you did?

A31. No. The RCN determination of the PG&E's assets inside the City is a complex process with hundreds of thousands of elements to be considered. This is in fact one strength of our analysis; we have very good knowledge of the assets to be valued. The challenge (I would not call it a weakness), is that we needed to make assumptions to make the data manageable, including the grouping of the assets in Construction Units. To make sure that this complex process was reasonable and conservative and did not introduce unintended errors, I used the Original Cost provided by PG&E from 2010 to 2021[31] and estimated the implied RCN by converting the original costs of the distribution plant, to 2022$ using the Handy-Whitman index for distribution assets for the Pacific Region. In doing this calculation, I assumed that the retirements had 25 years average age and that the 2010 plant had an average age of 15 years. For the plant additions, I used the year when they occurred for the conversion to 2022$. The table below shows the results of my calculations for the distribution plant, where I included the MV assets at the transmission-to-distribution substations which are also in PG&E's Original Costs. The table shows that with the contingency the RCN is [redacted]% of PG&E's Original Cost in 2022$, which is extremely close. When we add the 25% Owner's Cost, the RCN is [redacted]% of PG&E's Original Cost (This is [redacted]% higher than the RCN calculation). This seems to indicate that the Owner's Cost is conservative. This comparison shows the validity of the distribution RCN calculations.

[30] Attachment Z to Appendix IV (PGE000103594.xlsx).

[31] Attachment Q to Appendix IV (PGE000082649).

PG&E Distribution Assets' Original Cost in 2022$ M	[redacted]

RCN Calculation	2022$ M	Ratio
Distribution Assets	[redacted]	
MV Substations	[redacted]	
MV in Transmission	[redacted]	
Sub total	[redacted]	[redacted]
Contingency	[redacted]	
Total before Owner's Cost	[redacted]	[redacted]
Owners Cost	[redacted]	
Total	[redacted]	[redacted]

I did a similar analysis for the transmission plant. In this case, I assumed that the 2010 plant had an average life of 25 years because the transmission assets have a longer life than distribution assets. I used the Handy-Whitman index for transmission plant Pacific Region to convert the original costs to 2022$. The table below shows the results of my calculations for the transmission plant. The transmission assets in the table do not include the MV assets and the transformers, because this is not included in PG&E's original cost.[32] The table shows that calculated RCN with the 10% contingency is [redacted]% of PG&E's original cost in 2022$. When the 25% Owner's Cost is included, the RCN is [redacted]% of PG&E's original cost in 2022$. This also confirms the validity of the transmission RCN calculations.

Transmission Asset's Original Cost in 2022$	[redacted]

RCN Calculation		Ratio
Total Transmission 115 kV & above	[redacted]	[redacted]
Contingency	[redacted]	
Total before Owner's Cost	[redacted]	[redacted]
Owners Cost	[redacted]	
Total	[redacted]	[redacted]

Q32. Is PG&E's planned Egbert Switching Station Project included in the RCN?

[32] *See* Attachment Q to Appendix IV (PGE000082649).

A32. The substation RCN does not include future assets that PG&E expects to develop in the City, in particular the planned new 230 kV Egbert switching station. The California Public Utilities Commission issued a Certificate of Public Convenience and Necessity for this project in 2020 in Decision 20-06-037, but PG&E has not yet started construction. This new transmission 230 kV switching station is intended to improve the reliability of PG&E's transmission service to the City. Currently, the electricity supply to the City is critically dependent on the Martin substation. The City would become disconnected if this substation were lost due to a major event. The TBC only has capacity for about 40% of the City's load, and also may not be able to deliver any power to the City's distribution system during an outage at Martin due to the lack of alternating current supply to the City. While likelihood of this event is very low, the consequences are very high. The Egbert Switching Station would maintain an additional level of supply in this unlikely event, and will provide additional reliability when built and operational.

IV. AGE OF DISTRIBUTION AND TRANSMISSION ASSETS

Q33. Did you assess the age of the PG&E s electrical assets that the City intends to acquire?

A33. Yes, while assembling the inventory, my team and I compiled age information on the distribution and transmission assets based on PG&E's data. The age analysis is dependent on the quality of information provided by PG&E. I used the data provided for hundreds of thousands of assets, including but not limited to asset geodatabases, single line drawings, inspections, and analysis of the system to verify the data to the extent feasible. In a small number of cases, I did find discrepancies in the data.

For the transmission analysis, PG&E provided install dates which I used to determine ages for its transmission lines and the major equipment in the seven transmission-to-distribution substations. During the inspections, I verified the age of equipment in these substations. [redacted]

[redacted]

With respect to the transmission lines, PG&E provided install dates for each of the transmission lines. [redacted] After further research, I located documents that PG&E submitted to the California Public Utilities Commission, indicating that this XPLE line became operational in 2010.[33] In addition, the documents indicate that PG&E also replaced A-H-W #2 at the same time. The replacement in 2010 was most likely an XPLE line because that was the technology used at that time and both lines have identical ratings [redacted]

PG&E provided install dates for major equipment in the MV substations, which I used in the report.[34] I verified data during inspections of a selected number of substations [redacted]

---

[33] Attachment V to Appendix IV (E-mail from Brian K. Cherry, Vice President of Regulatory Relations, PG&E, to Paul Clanon, Executive Director, Cal. P.U.C. (Oct. 25, 2010), p. 4-2) and attachment U to Appendix IV (PG&E Advice Letter 3317-E, Submitted to CPUC September 13, 2008).

[34] Attachment H to Appendix IV (PGE000073870.xlsx).

[35] Appendix I, p. 14.

After seeing missing data, the City requested the missing age data or a method for estimating the dates, but PG&E only provided insignificant additional data regarding distribution assets and declined to provide the average age of these distribution assets.[36]

Due to the variations in the asset types and construction techniques, my team and I used engineering judgment to derive assumptions on the age data for each asset type with missing data to calculate an average age for distribution asset types in the inventory.

For many distribution asset types, to develop these estimates, I assessed the amount of missing data per asset type and created histograms for each asset type using installation dates that were provided.[37] The installation trends illustrated in the histogram informed the selection of an appropriate average installation date for the assets without age data. In making this selection, I assumed that assets without age data are older than assets that have records of the installation date, and that the assets without dates should be clustered around the years when there was an appreciable increase in the installations. This is a reasonable assumption and is based on my judgement that record-keeping has improved over time, it is most likely that items without dates were installed at the same time as a large number of the same items were being installed, and that it is more likely to omit date information when there is a large amount of ongoing work.

For some distribution asset types, I determined it was most appropriate to estimate the average installation date for assets that had no records by assuming that their average installation date was the same as the average installation date of other associated equipment that in practice is installed at the same time as the equipment without records. I made these assumptions based on my knowledge of how electrical systems are built. For instance, padmounts are placed in service at the same time as the equipment they support.

The age data assumptions are described in each of the individual "Asset Age" subsections within Section 3 of Appendix I.

[36] Appendix I, p. 14.

[37] *See* Section 3 of Appendix I (subsections titled "Asset Age")

V. CONDITION OF PG&E'S DISTRIBUTION AND TRANMISSION ASSETS

Q34. As part of the valuation, do you conduct inspections of PG&E's distribution and transmission assets?

A34. Yes. My team and I developed a plan to inspect a representative sample of the electrical assets that the City intends to acquire. My team and I inspected the seven transmission-to-distribution substations from December 6 to 8, 2023, a sample of the underground transmission cables facilities from January 18 to 19, 2023, and MV Substations on February 2 and 3, 2023. In addition, my colleague, Jorge Matheus, inspected distribution manholes from January 30 to February 2, 2023. Collectively, we took thousands of photographs during the inspections.

Q35. What is your opinion of the overall conditional of PG&E's distribution assets in the City?

A35. [redacted]

Q36. What is your opinion of the condition of PG&E's MV substations in the City?

A36. [redacted]

Q37. What is your opinion of the condition of the other PG&E distribution assets in the City?

A37. [redacted]

---

[38] *See* Section 6.1.3 of Appendix I (Marina (F) MV Substation).

[39] *See* Appendix I, pp. 89, 91, 96 and 97.

[redacted]

Q38. What is your opinion of the condition of the transmission assets?

A38. [redacted][40]

VI. FINAL QUESTIONS/CONCLUSIONS

Q39. Are you sponsoring any Appendices to your testimony?

A39. Yes. I am sponsoring the appendices to my testimony, as described below:

Appendix I: San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 10, 2023), Volume I: Executive Summary, Distribution Inventory and RCN

Appendix II: Volume II San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 10, 2023), Volume II: Transmission Inventory and RCN

Appendix III: Resume/CV

Appendix IV: Attachments to Reports

Q40. Does that conclude your testimony?

A40. Yes.

---

[40] *See* Appendix II (Section 6.2.2 (Hunters Point) and Section 6.2.3 (Bayshore)).

Docket:	P.21-07-012
Exhibit No.:	CCSF- _____
Date Served:	April 10, 2023
ALJ:	R. Lirag
Witness:	T. Runde

PUBLIC VERSION

PREPARED DIRECT TESTIMONY

OF

TIMOTHY P. RUNDE

ON BEHALF OF

THE CITY AND COUNTY OF SAN FRANCISCO

APRIL 10, 2023

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF TIMOTHY P. RUNDE

This testimony summarizes the appraisal and valuation of real property consisting of Pacific Gas & Electric Company's electrical transmission and distribution substation assets, which provide electric service to the City and County of San Francisco, California. The valuation analysis pertains only to land and improvements. It excludes the transmission and distribution equipment, fixtures, and any non-real property components. This testimony summarizes and references throughout the Fair Market Value Appraisal Report prepared by witness Mr. Timothy P. Runde. The Fair Market Value Appraisal Report ("Valuation Report") is attached hereto as **Appendix I.**

I. INTRODUCTION

Q1. Please state your name, occupation, and business address.

A1. My name is Timothy P. Runde. I am the President of Runde & Partners, Inc.. My business address is One Sansome Street, Suite 3500, San Francisco, California, 94104.

Q2. Please summarize your educational and professional background.

A2. I am the President and Founding Partner of Runde & Partners, Inc., a full-service real estate appraisal and consulting company headquartered in San Francisco, California. Prior to forming Runde & Partners, I was a Partner with Carneghi and Partners. I have over 30 years of commercial real estate appraisal experience encompassing a wide range of property types, including commercial office, industrial, retail and multi-family assignments. I also have developed expertise in advanced practice areas including condemnation and providing expert testimony across a variety of forums. I received a Master of Science degree in Real Estate Appraisal and Investment Analysis and certified in California as a General Real Estate Appraiser. I also hold the MAI designation from the Appraisal Institute. My qualifications are included as Attachment D to Appendix I.

Q3. On whose behalf are you submitting testimony?

A3. I submit this testimony and the attached Appendix I containing my Fair Market Value Appraisal Report on behalf of the City and County of San Francisco ("San Francisco").

Q4. What is the purpose of your testimony?

A4. The purpose of my direct testimony is to provide an estimate of the as-is, fair market value for the real property component of PG&E's electrical transmission and distribution grid that serves the City and County of San Francisco, California. The real property appraised consists of 31 properties and will be referred to as the "Subject Properties" in my testimony. My Fair Market Value Appraisal Report ("Valuation Report") on the Subject Properties and relevant attachments are attached hereto as Appendix I.

Q5. What is your recommended estimate of fair market value for the Subject Properties?

A5. Based on the research and analyses contained in my Valuation Report, I determined three fair market values of the unencumbered fee simple interest in the Subject Properties, in their as-is condition, as of July 27, 2021. The estimated fair market values include the total value of Properties 1 to 30, then distinguished by three asset scenarios based on a portion of Property 31 (Martin Substation located in Brisbane, California) for acquisition:[1]

Martin Scenario 1 (Props. 1-30, plus Full 115 KV of Prop. 31)	**$ 491,750,000**
Martin Scenario 2 (Props. 1-30, plus Partial 115 KV of Prop. 31)	**$ 466,150,000**
No Martin Asset Scenario (Props. 1-30 only)	**$ 442,850,000**

Q6. How did you arrive at your recommended fair market values provided in Question 5, above?

A6. As further described in my Valuation Report and summarized below, I determined these recommended values based on the Cost Approach which first values the land by comparison to recent, comparable land sales. The depreciated replacement cost of any

[1] Appendix I – Valuation Report, p. 3.

existing functional structural and site improvements is then added, providing a market value indication for the property. The three fair market values were then determined based on the three asset scenarios related to the partial acquisition of Property 31 (the Martin Substation).[2]

II. VALUATION STANDARDS

Q7. Please define the property terms "fee simple interest" and "easement," as used in your Valuation Report.

A7. When referring to a property right as a "fee simple interest" it means absolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, eminent domain, police power, and escheat. Easement refers to the right to use another's land for a stated purpose.[3]

Q8. How do you define Fair Market Value in your appraisal of the Subject Properties?

A8. The definition of Fair Market Value is derived from the California Code of Civil Procedure as follows:[4]

> a. The fair-market value of the property taken is the highest price on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available.
>
> b. The fair-market value of property taken for which there is no relevant comparable market is its value on the date of valuation as determined by any method of valuation that is just and equitable.

---

[2] Appendix I – Valuation Report, pp. 31-34.

[3] *The Dictionary of Real Estate Appraisal*, 7th Edition, 2022, pp. 58 and 79.

[4] California Code of Civil Procedure Section 1263.320.

Q9. What date of valuation did you use in your appraisal?

A9. The Fair Market Value of the Subject Properties was determined as of July 27, 2021, which is the date of the filing of the instant petition for valuation of PG&E's assets in proceeding P.21-07-012.

Q10. What is your understanding of the term "Highest and Best Use" as the term is used in the definition of Fair Market Value?

A10. I applied the "highest and best use" as defined by the *Dictionary of Real Estate Appraisal* as follows:[5]

> The reasonably probable use of property that results in the highest value. The four criteria that the highest and best use must meet are legal permissibility, physical possibility, financial feasibility, and maximum productivity.

Determination of the highest and best use for a property is essential in order to select the proper comparables, which must have a similar highest and best use. The highest and best use of the subject property can also influence the methodology employed in the valuation process.

Q11. What did you determine is the Highest and Best Use of the Subject Properties?

A11. The highest and best use of the subject property is the <u>current use</u> as the real property component supporting the electrical grid serving San Francisco. Redevelopment of the individual sites for alternate uses would not be practical, as the grid functionality would be adversely affected. Further, as shown in the Valuation Report, the sites improved with enclosed substations, as identified in Table A-2, add significant value to the underlying land and should be retained. Finally, most of the older structures are historically protected such that demolition and redevelopment would not be permitted.[6]

---

[5] *The Dictionary of Real Estate Appraisal*, 7th Edition, 2022, p. 89.

[6] Appendix I – Valuation Report, Attachment A: Table A-2 (Structural Improvement Summary).

Q12. Were any assumptions made or limiting conditions considered in your appraisal of the Subject Properties?

A12. Yes. Any assumptions and limiting conditions are discussed in detail in Section I.H of my Valuation Report.[7]

III. SUBJECT PROPERTIES

Q13. Please generally describe the Subject Properties appraised in your Valuation Report.

A13. The Subject Properties appraised are the real property component of Pacific Gas & Electric Company's electrical transmission and distribution grid that serves the City and County of San Francisco. My appraisal addresses only the real property, including land and structural improvements. I did not appraise transmission and distribution equipment, fixtures, or any non-real property components. I also reviewed over 2,000 appurtenant easements, licenses, permits, agreements, and similar rights to use property owned in fee by others.

Properties 1 through 30 are located within the City and County of San Francisco, California, while Property 31 (Martin Substation) is located within the City of Brisbane, San Mateo County, California. These subject properties are geographically depicted on a map in Attachment A of my Valuation Report.[8]

The Subject Properties consist of 31 individual sites, 10 of which are improved with special-purpose industrial buildings that house electrical equipment (Properties 1, 2, 4, 5, 6, 7, 8, 9, 11, and 12).[9] Property 31 is a portion of the Martin substation. The remaining 20 sites consist of unenclosed distribution substations that either lack building

---

[7] Appendix I – Valuation Report, pp. 3-5.

[8] Appendix I – Valuation Report, Attachment A: Subject Property Identification Map.

[9] Appendix I – Valuation Report, Attachment A: Table A-2 (Structural Improvement Summary).

improvements entirely or include functionally obsolete buildings that are vacant and unused (Properties 7, 15, & 24).[10] All the subject sites are fully improved urban parcels.[11]

Q14. Did you personally inspect any of the Subject Properties?

A14. Yes, I made a personal inspection of each and every subject property. I inspected the interior and exterior of subject properties 1, 2, 4, 5, 6, 7, 8, 9, 11, and 12 with the owner's representatives on February 1, 2023. I personally inspected the remaining properties from the public street (exterior only) between September 14, 2022 and February 21, 2023.

Q15. What sources of information or data informed your appraisal of the Subject Properties?

A15. In addition to personally conducting on-site inspections of the subject properties, I derived site areas from my review of State Board of Equalization (SBE) Maps, Assessor's Maps, and aerial measurements from satellite imagery. I derived building areas from a combination of field measurements during the inspection, aerial measurements from satellite imagery, building plans, and recorded documentation in the public record. I also reviewed public record documents made available through the San Francisco Planning Department for historical ratings of buildings on the Subject Properties. Finally, I reviewed various data request responses from PG&E regarding the subject properties, which provided information on the Subject Properties including building age, size, use, and environmental conditions.

Q16. What characteristics of the Subject Properties informed your appraisal of the Subject Properties?

A16. For land valuation of the Subject Properties, I considered location, size, condition, use, topography, site improvements, and land use restrictions, including zoning, historical

---

[10] Appendix I – Valuation Report, p. 26.

[11] *See* Appendix I – Valuation Report, Attachment A: State Board of Equalization maps (Confidential and Redacted in Public Version).

designations, and environmental conditions. The physical characteristics of the improvements and condition of the Subject Properties are discussed in detail in Section III.F, as well as Tables A-1 and A-2 of Attachment A.[12]

Q17. What is the significance of identifying historic resources on the Subject Properties in the context of your valuation analysis?

A17. Once a property is designated as a historic resource, its historical contribution becomes a factor to be considered in the approval of modifications to the improvements. Structures that are identified as historic resources cannot be significantly modified, which typically limits the potential uses to the existing use or a similar use that can be accommodated by the existing improvements. As a practical matter, historical ratings can severely constrain the ability to modify the exterior of the structure, and demolition is typically not permitted. In some cases, expansion may be allowed but is subject to strict review. Any historic ratings on Subject Properties represent an additional constraint limiting alternate uses of the sites and is considered in the highest and best use analysis.

Q18. Please summarize your findings on any historical designations found on the Subject Properties.

A18. In my review of historical ratings, I found that several properties (Properties 5, 7, 9, 11, and 12) include structures that have received historical ratings and/or are within a historic district. There are also properties that have not been rated but are eligible for a historic rating once evaluated (Properties 1, 6 and 8). Further discussion on these particular Subject Properties is presented in my Valuation Report.[13]

Q19. What is the significance of environmental conditions of a subject property for purposes of determining a fair market valuation?

A19. Environmental conditions relate to any existing or historic environmental contamination or hazards known for the subject property. Land use restrictions in place due to

---

[12] Appendix I – Valuation Report, Attachment A: Table A-1 (Subject Property Identification) and Table A-2 (Structural Improvement Summary).

[13] Appendix I – Valuation Report, pp. 10-11.

contamination prohibit certain uses for a subject property (*e.g.,* residential, hospital, schools) and can restrict or reduce the potential uses of a subject property. In the case of the Subject Properties, any existing contamination restricts the highest and best use to industrial or similar uses, which informs the selection and analysis of the comparable land sales used to value the site.

Q20. Did you observe any environmental conditions affecting the Subject Properties?

A20. My review considered the contaminated status of Property 2 (Potrero), Property 3 (Hunters Point), Property 10 (Marina), and Property 31 (Martin).[14] These observations were made based on documents provided by PG&E in responses to data requests.

Q21. Are there any easements or restrictions burdening the Subject Properties?

A21. Preliminary title reports were not provided for review. We assumed clear and marketable title, with no adverse easements that would adversely affect the utility or marketability of title to the subject.

Q22. Please describe the appurtenant easements you reviewed in your valuation of the Subject Properties.

A22. The Subject Properties include over 2,000 appurtenant easements, licenses, permits, agreements, and similar rights to use property owned in fee by others. The vast majority of these rights consisted of easements granted without consideration as a condition of providing electrical service. The value of the majority of these easements for which consideration was paid, as well as the majority of the easements where no consideration was paid, is subsumed in the market value conclusion of the land sale comparables. Each of the comparables reflects a site serviced with electricity, which enhances its value. Since electrical service requires a functioning electrical grid for which these various easements are an integral part, the land value based on comparable land sales necessarily

[14] Appendix I – Valuation Report, pp. 9-10.

includes the contributory value of these easements. This avoids double-counting the benefit conferred by the various easements.[15]

Q23. Are there any zoning restrictions burdening the Subject Properties?

A23. Table A-1 of Attachment A identifies the zoning designation of each Subject Property.[16] The subject utility use is permitted by right or with conditional use authorization in the zoning for all of the Subject Properties except Properties 1, 5, 9, 11, 13, 15, 19, 21, 23, 26 and 28, all of which are zoned for residential use. These properties represent legal, non-conforming uses, which may predate the current zoning.

IV. VALUATION METHODOLOGY

Q24. Please describe the valuation approaches applied in determining the fair market value of the Subject Properties.

A24. The valuation of any parcel of real estate is typically derived through three primary approaches to the market value – (i) cost, (ii) sales comparison, and (iii) income.[17] The *Cost Approach* is based on the premise that except in the most unusual circumstances, the value of a property cannot exceed the cost of acquiring a similarly functional site and constructing similar building improvements. The *Cost Approach* begins with an estimation of land value as if vacant. The replacement cost of the improvements is then estimated, and includes deductions for estimated depreciation (such as physical deterioration, functional obsolescence and economic obsolescence). The *Sales Comparison Approach* is based on the principle of substitution, where the value of a property is governed by the prices generally obtained for similar properties. Lastly, the *Income Approach* is based on the property's ability to produce a net annual income.

---

[15] Appendix I – Valuation Report, pp. 27-28.

[16] Appendix I – Valuation Report, Attachment A, Table A-1.

[17] *See* Appendix I – Valuation Report, p. 30 for definitions of the market value approaches.

The Subject Properties represent special purpose, limited market properties, for which the *Cost Approach* is the most reliable method of valuing the real property (land and improvements). The *Sales Comparison Approach* is not applicable to valuing the real property due to the unique nature of the improvements, and the paucity of comparable sales transactions involving real property only. While the *Income Approach* is a reliable method for valuing the operating enterprise, it is unreliable for valuing the real estate component only, because the buyer of such property would be unable to look to the market to determine the income such properties can generate in light of the regulatory constraints placed on such special purpose properties. Therefore, the *Sales Comparison* and *Income Approach* are not used in this appraisal to value the real property. The Subject Properties are therefore valued using the cost approach.

Q25. What indicators of value did you develop under the Cost Approach you used?

A25. Under the Cost Approach, the value of each Subject Property site is estimated assuming the site is unimproved, vacant land. Land values for each Subject Property were based on a comparison with recent sales of land in the surrounding area and considering the planned use of the comparable property.[18] The comparable land sales are shown in tabular form in Attachment B to my Valuation Report and keyed to maps that follow the tables.[19]

Next, the replacement cost new ("RCN")[20] is estimated for any existing, functional site and/or structural building improvements.[21] All forms of depreciation are then deducted from the RCN estimate, resulting in a depreciated replacement cost, or Replacement Cost

---

[18] Appendix I – Valuation Report, pp. 31-33.

[19] Appendix I – Valuation Report, Attachment B (Comparable Data).

[20] *Replacement Cost New* is the cost of replacing an existing property with a property of equivalent utility as of a particular date.

[21] Appendix I – Valuation Report, p. 33 for analysis of RCN for Subject Properties.

New Less Depreciation ("RCNLD").[22] The calculations of RCN, depreciation, and RCNLD for each subject property is shown in Tables C-1 and C-2 in Attachment C of the Valuation Report.

Finally, the land value is then added to the RCNLD resulting in a market value estimate for each Subject Property.[23] The total fair market value for all 31 Subject Properties includes three values based on the asset scenarios related to the Property 31 (Martin Substation). The value conclusions for each property are shown in Table C-3.[24]

Q26. Please explain the three asset scenarios for Property 31 (Martin Substation) resulting in three fair market value recommendations.

A26. Property 31 is the Martin Substation located in the City of Brisbane, San Mateo County. This property is appraised under three asset scenarios, which differ only in what portion of the Martin substation is acquired.[25]

Martin Scenario 1 would include the entire 115 KV portion of the larger Martin substation, estimated at approximately 630,310 square feet (14.46 acres). This scenario consists of the northern portion of the larger substation. It would not include the portion of the site improved with the emergency preparedness building, the substation area at the southern portion of the site, or southeastern portion of the site area improved with the two industrial buildings adjacent to Bayshore Boulevard.[26]

Martin Scenario 2 includes only a portion of the 115 KV substation needed to serve San Francisco. It would further reduce the Scenario 1 area by excluding portions of the substation on the western and southeastern portions of the Scenario 1 area. While the

---

[22] Appendix I – Valuation Report, pp. 34.

[23] Appendix I – Valuation Report, pp. 34.

[24] Appendix I – Valuation Report, Attachment C, Table C-3 (Valuation Summary).

[25] Appendix I – Valuation Report, pp. 26-27.

[26] Appendix I – Valuation Report, p. 27 for an aerial view of Martin Scenario 1.

ultimate configuration is yet to be determined, it is estimated that the site area at Martin needed to accommodate these assets for Martin Scenario 2 is approximately 300,940 square feet (6.91 acres).

Finally, the ***No Martin Asset Scenario*** does not include any portion of the Martin substation, and thus reflects the total fair market value of Properties 1-30, only.

Q27. What is your recommended total fair market value for the Subject Properties?

A27. The estimated fair market values include the total value of Properties 1 to 30, then distinguished by the three asset scenarios depending on the portion acquired for Property 31 (Martin Substation):

Martin Scenario 1 (Props. 1-30, plus Full 115 KV of Prop. 31)	**$ 491,750,000**
Martin Scenario 2 (Props. 1-30, plus Partial 115 KV of Prop. 31)	**$ 466,150,000**
No Martin Asset Scenario (Props. 1-30 only)	**$ 442,850,000**

Q28. Does that conclude your testimony?

A28. Yes.

Docket:	P.21-07-012
Exhibit No.:	__________
Date Served:	April 10, 2023
ALJ:	R. Lirag
Witnesses:	N. Hughes and G. Rabon

PUBLIC

PREPARED

JOINT DIRECT TESTIMONY

OF

NANCY HELLER HUGHES, ASA, CDP

AND

GRANT RABON, ASA

ON BEHALF OF

THE CITY AND COUNTY OF SAN FRANCISCO

APRIL 10, 2023

PREPARED
JOINT DIRECT TESTIMONY OF
NANCY HELLER HUGHES, ASA, CDP
AND
GRANT RABON, ASA

<u>TABLE OF CONTENTS</u>

Page

<u>Appendices</u>

PREPARED
JOINT DIRECT TESTIMONY OF
NANCY HELLER HUGHES AND GRANT RABON

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A1. My name is Nancy Heller Hughes. I am a Principal at NewGen Strategies and Solutions, LLC ("NewGen"), a management and economic consulting firm specializing in the utility industry. My business address is 20014 Southeast 19th Street, Sammamish, Washington 98075.

A1. My name is Grant Rabon. I am a Partner at NewGen, and I work out of the Austin office of NewGen located at 8140 North Mopac Expressway, Suite 1-240, Austin, Texas 78759.

Q2. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A2. I, Nancy Hughes, graduated from the University of Chicago with a bachelor's degree in Business and Statistics in 1977 and a master's degree in Business Administration in 1978. I have worked as a consultant in the public utility industry since 1977 specializing in utility valuation, depreciation, rates, and regulation, and have testified as an expert witness on these issues before federal and state regulatory commissions, city councils, and courts of law. I am an Accredited Senior Appraiser ("ASA") of public utility property certified by the American Society of Appraisers and a Certified Depreciation Professional ("CDP") certified by the Society of Depreciation Professionals. Additional information regarding my professional experience is provided in the attached Statement of Qualifications, and my attached résumé (Appendix I).

A2. I, Grant Rabon, was awarded a Bachelor of Science degree in Chemical Engineering from Texas A&M University in College Station, as well as a Master of Business Administration from the University of Texas at Austin. I am an Accredited Senior Appraiser ("ASA") of public utility property certified by the American Society of Appraisers. Since 2005, I have been assisting utilities with the conduct of cost of service and rate design studies, utility appraisals, financial feasibility studies, and other management consulting engagements for electric, natural gas, water, wastewater, and solid waste utilities. Additional information regarding my professional experience is provided in the attached Statement of Qualifications, and my attached résumé (Appendix II).

Q3. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A3. We are testifying on behalf of the City and County of San Francisco ("CCSF").

Q4. ARE YOU SPONSORING ANY APPENDICES TO YOUR TESTIMONY?

A4. Yes. We are sponsoring the appendices to our testimony, as described below:

1. Résumé of Nancy Heller Hughes (Appendix I)
2. Résumé of Grant Rabon (Appendix II)
3. N. Hughes, G. Rabon, NewGen Strategies & Solutions, *Appraisal of PG&E Electrical Distribution and Transmission Facilities in the City of San Francisco* (2023) (Appendix III)
4. Excerpted Supplemental PG&E Response to DR-CCSF_04-Q04, attachment PGE000082649 (Appendix IV)

Q5. SINCE YOU ARE FILING JOINT TESTIMONY, PLEASE EXPLAIN EACH OF YOUR ROLES IN PREPARING YOUR EXPERT APPRAISAL REPORT (APPENDIX III) AND THIS JOINT TESTIMONY.

A5. We, Ms. Hughes and Mr. Rabon, collaborated in developing the methodology, reviewing data and inputs, evaluating the results of the appraisal analyses, and preparing our expert appraisal report (Appendix III). Mr. Rabon was responsible for performing the calculations in the appraisal analyses. Ms. Hughes and Mr. Rabon jointly prepared all sections of this testimony.

II. PURPOSE OF TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A6. The purpose of our direct testimony is to provide an estimate of Fair Market Value for the portion of the Pacific Gas and Electric Company ("PG&E") owned and operated electric system used to provide service within the boundaries of CCSF, including some facilities located outside of the City, that serve the San Francisco electrical grid. This portion of the PG&E electric system will be referred to as the "Subject Property" in our testimony.[1]

III. SUMMARY OF APPRAISAL AND RECOMMENDATION

Q7. WHAT IS YOUR RECOMMENDED ESTIMATE OF FAIR MARKET VALUE FOR THE SUBJECT PROPERTY?

A7. Based upon information received from PG&E, additional analysis prepared on behalf of CCSF by Dr. Nelson Bacalao, Principal with Siemens PTI Consulting and principal author

[1] The Subject Property is described in more detail in the direct testimony of Nelson Bacalao of Siemens PTI Consulting and the direct testimony of Timothy Runde of Runde & Partners, Inc., as well as NewGen's written appraisal report, attached to this testimony as Appendix III.

of the engineering report prepared on behalf of CCSF titled *San Francisco Grid Procurement Engineering Services – Asset Valuation, Volumes I and II* (Appendices I and II to the Advisian-Siemens Report), prepared by Advisian, Worley Group with Siemens Industry, Inc. (collectively referred to as "Advisian-Siemens"), and the appraisal report prepared on behalf of CCSF by Timothy Runde of Runde & Partners, Inc. (Appendix I to Testimony of Timothy P. Runde) regarding the fair market value of the real property component of the Subject Property, our analysis concludes that $2,374,000,000 reflects the Fair Market Value of the Subject Property.

Q8. HOW DID YOU ARRIVE AT YOUR RECOMMENDED ESTIMATE OF FAIR MARKET VALUE?

A8. As further described in our appraisal report (Appendix III), and summarized below, we determined this recommended estimate of Fair Market Value after first assessing the value of the Subject Property under three separate valuation approaches that are generally accepted in the industry, and then determining which of the three approaches most appropriately represents the Fair Market Value of PG&E's property. Table 1 summarizes the estimates we derived under each of the valuation methodologies.

Table 1
Summary of Indicators of Value

	Indicators of Value
Cost Approach:	
Reproduction Cost New	$ 9,902,232,000
Less: Physical Deterioration and Net Salvage	(5,545,038,000)
Less: Functional Obsolescence	-
Less: Economic Obsolescence	(1,983,170,000)
Reproduction Cost New Less Depreciation (RCNLD)	$ 2,374,024,000
Original Cost	$ 3,836,832,000
Less: Physical Deterioration and Net Salvage	(2,042,130,000)
Original Cost Less Depreciation (OCLD) – Rate Base Value	$ 1,794,702,000
Income Approach:	
Discounted Cash Flow	$ 2,374,024,000
Sales Comparison Approach:	
Guideline Sale Transactions	$ 2,334,403,000
Estimated Fair Market Value of Subject Property as of July 27, 2021	**$ 2,374,000,000**

Source: Appendix III, Table 5-1, based on Martin Acquisition Scenario 1.

We determined that the estimate derived pursuant to the income approach most fairly represents the Fair Market Value of the Subject Property for several reasons. First, our conclusion accounts for the effect of utility rate regulation in valuing public utility property. Pursuant to California Public Utilities Commission's ("CPUC") ratemaking process, rate regulated utilities are allowed the opportunity to earn a reasonable rate of return on their rate base (predominately composed of the original cost less depreciation ("OCLD") value of the non-contributed plant assets). The income approach value closely approximates the rate of return regulated utilities like PG&E can earn under this established regulatory regime. Second, the income approach reflects the reality that an informed buyer would not be willing to pay a price for the Subject Property that exceeds the income value of the property. Finally, the results of the sales comparison approach generally support the income value for the Subject Property.

After consideration of the indicators of value developed using generally accepted approaches to valuation, given the relative strengths and weaknesses of each and the analyses and assumptions used therein, we concluded that the Fair Market Value of the Subject Property as of July 27, 2021 is equal to $2,374,000,000 as indicated by the income approach (rounded to the nearest million). This figure represents what PG&E should receive to fairly compensate it for the value of the property. It does not include severance damages, if any.

One additional observation with regard to the Fair Market Value of the Subject Property is that this value reflects certain specific assumptions regarding the CCSF's potential acquisition of a portion of the Martin Substation – what CCSF refers to as Martin Acquisition Scenario 1 (Base Case). At CCSF's request, we developed the Fair Market Value of the Subject Property using three different acquisition scenarios for property at PG&E's Martin substation, as discussed in Section VIII of this testimony.

Q9. PLEASE DESCRIBE THE THREE MARTIN SUBSTATION ACQUISITION SCENARIOS EVALUATED IN YOUR APPRAISAL.

A9. CCSF requested that we appraise the Fair Market Value of the Subject Property under three electric system asset scenarios concerning PG&E's Martin substation, located in San Mateo County, California. As summarized below, the three scenarios contemplate the following alternative potential acquisition options:

- Martin Scenario 1 (Base Case) includes the 230/115 kV transformers, the entire 115 kV switchyard, the 115/60 kV transformer as well as the 115/12 kV transformers and the medium voltage switchyard.
- Martin Scenario 2 includes the 230/115 kV transformers, a portion of the Martin 115 kV system, 115/12 kV transformers and the medium voltage switchyard. This scenario does not include the 115/60 kV transformer or related 60 kV assets.
- Martin Scenario 3 assumes no Martin assets would be acquired.

In none of the Martin substation acquisition scenarios does CCSF acquire the 230 kV bus at Martin substation.

Our appraisal report (Appendix III) primarily addresses the value of the Subject Property under Martin Scenario 1. However, we also evaluated the impact of the alternative Martin scenarios on the Fair Market Value of the Subject Property pursuant to the same generally accepted valuation approaches detailed in the main section of our appraisal report. These results are shown in Attachment E of our appraisal report and summarized in Table 2 below.

Table 2
Impact of Martin Acquisition Scenarios on Total Valuation of Subject Property

	Estimated Fair Market Value of Subject Property	Difference in FMV from Scenario 1
Martin Scenario 1 (Base Case)	**$ 2,374,000,000**	
Martin Scenario 2	**$ 2,319,000,000**	**($ 55,000,000)**
Martin Scenario 3 (No Martin)	**$ 2,197,000,000**	**($ 177,000,000)**

Source: Appendix III, Attachment E, estimated Fair Market Value as of July 27, 2021.

Q10. HOW DOES THE FAIR MARKET VALUE OF THE SUBJECT PROPERTY COMPARE UNDER THE THREE MARTIN ACQUISITION SCENARIOS YOU ANALYZED?

A10. As shown in Table 2, the estimated Fair Market Value of the Subject Property under Martin Scenarios 2 and 3 are less than under Martin Scenario 1. This is because fewer PG&E assets are acquired under Martin Scenarios 2 and 3 than under Martin Scenario 1. Under Martin Scenario 3, no assets at the Martin Substation would be acquired by the CCSF.

IV. VALUATION STANDARDS

Q11. WHAT DATE OF VALUATION DID YOU USE IN YOUR APPRAISAL?

A11. The Fair Market Value of the Subject Property was determined as of July 27, 2021, which is the date CCSF filed its petition for valuation of PG&E's assets in proceeding P.21-07-012.[2]

Q12. WHAT DEFINITION OF FAIR MARKET VALUE DID YOU ASSUME FOR YOUR APPRAISAL?

A12. Our appraisal of the Subject Property assumed the following Fair Market Value definition:

> a) The fair market value of the property taken is the highest price on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full

[2] *See* Pub. Util. Code, § 1411: "The just compensation shall be fixed by the commission as of the day on which the petition was filed with the commission."

knowledge of all the uses and purposes for which the property is reasonably adaptable and available.

b) The fair market value of property taken for which there is no relevant, comparable market is its value on the date of valuation as determined by any method of valuation that is just and equitable.[3]

Q13. WHAT IS YOUR UNDERSTANDING OF THE PHRASE "HIGHEST PRICE," AS THAT TERM IS USED IN THE DEFINITION OF FAIR MARKET VALUE?

A13. The Fair Market Value is the amount that a seller would be willing to accept for the property that the buyer would also be willing to pay, with "full knowledge of all the uses and purposes for which the property is reasonably adaptable and available."

Q14. WHAT ARE THE "USES AND PURPOSES" FOR WHICH THE SUBJECT PROPERTY IS "REASONABLY ADAPTABLE AND AVAILABLE"?

A14. The Subject Property is only "reasonably adaptable and available" for the continued provision of electric utility services to end-users located within the boundaries of CCSF. Thus, in our opinion, the fair market value of the Subject Property in continued use for the provision of electric utility services best reflects the Subject Property's "highest price." The Subject Property's continued use for electric utility services also reflects the "highest and best use" of the property, which is similarly defined by the American Society of Appraisers as: "the most reasonably probable and legal use of a property (including

[3] *See* California Code of Civil Procedure Section 1263.320.

machinery and equipment), which is physically possible, appropriately supported, financially feasible, and that results in the highest value."[4]

V. APPRAISAL APPROACHES

Q15. PLEASE OUTLINE THE THREE GENERALLY ACCEPTED APPROACHES TO VALUING UTILITY PROPERTY.

A15. The three generally accepted approaches to valuing utility property are the: (1) income approach, (2) cost approach, and (3) sales comparison approach.[5] The income approach is based on capitalizing or determining the present value of the prospective net earnings from the Subject Property. The cost approach is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the Subject Property. The sales comparison approach is based on comparing the Subject Property to recent fair market sales of similar facilities under similar circumstances between a willing buyer and a willing seller. Each of these valuation approaches generates a unique estimate of a property's fair market value.

Q16. WHY IS MORE THAN ONE VALUATION APPROACH USED TO ESTIMATE A PROPERTY'S FAIR MARKET VALUE?

A16. Each valuation approach develops value indicators from a different perspective and set of data. However, it is important to note that the three broad approaches are not independent

[4] American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets*, Fourth Edition, Glossary of Terms, p. 537.

[5] The sales comparison approach is also referred to as the market approach.

of each other but are interrelated.[6] For this reason, our appraisals of utility property typically develop value indicators based on all three generally accepted approaches to valuation. In addition, Uniform Standards of Professional Appraisal Practice ("USPAP") Standards Rule 7-4 requires the appraiser to consider and use all three approaches to valuation (cost, income, and sales comparison) when necessary to provide credible assignment results.

Q17. WHAT HAPPENS IF THE VALUES GENERATED BY THE THREE APPROACHES DIFFER SIGNIFICANTLY?

A17. Ideally, all three approaches will support the same value conclusion, or at least define a narrow range. If one of the approaches results in an indicator of value that is significantly different from the other indicators of value, the appraiser needs to understand the causes and reconsider the analysis.[7] That is what we were obliged to do for this appraisal given the significantly different value generated by RCNLD as compared to the income and sales comparison approaches. As discussed in our testimony, we concluded that the RCNLD (without adjustment for functional/economic obsolescence) generated a value that could not be justified vis-à-vis the income earning capability of the Subject Property or the sales comparison approach and, therefore, should be depreciated to reflect the assets' economic obsolescence. This issue is addressed in Sections V.B and VII of this testimony.

---

[6] Shannon P. Pratt, *Valuing A Business, The Analysis and Appraisal of Closely Held Companies*, Fifth Edition, p. 62.

[7] American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets*, Fourth Edition, p. 176.

A. <u>INCOME APPROACH</u>

Q18. PLEASE DESCRIBE THE INCOME APPROACH.

A18. The income approach estimates the value of the Subject Property by capitalizing or determining the present value of anticipated economic benefits from the property in the future as a going concern. One method of determining value under the income approach is the discounted cash flow ("DCF") method. Under the DCF method, the direct economic benefits derived from continued ownership of the Subject Property are expressed in terms of free cash flow, which represents the total cash flow generated by the going concern that is available to the providers of both debt and equity capital.

The calculation of free cash flow is illustrated as follows:

	Annual Operating Revenues
Less:	*Annual Operating Expenses*
Equals:	*Pre-tax Net Operating Income*
Less:	*Income Taxes*
Equals:	*Earnings Before Interest,*
	Depreciation & Amortization (EBIDA)
Less:	*Future Capital Expenditures*
	Net Changes in Working Capital
Equals:	*Free Cash Flow*

We developed a ten-year forecast (2021-2030) of free cash flow and then calculated the present value of this stream of earnings to the date of valuation. It is common to forecast the free cash flow in a DCF analysis for five to ten years, and we used ten years for our analysis. However, because the utility is expected to continue in operation beyond ten years, we added to this value the present value of the calculated terminal value of the business as a going concern into perpetuity (i.e., after the first ten years of forecasted free cash flows).[8] In other words, the terminal value represents the value of the business as a going concern starting at the end of the tenth year of the forecast. Adding the present value of the free cash flows over the first ten years to the present value of the free cash flows after the first ten years provides the total present value of free cash flows as a going concern into perpetuity.

Q19. HOW DID YOU DETERMINE THE ANNUAL OPERATING REVENUES IN THE FREE CASH FLOW FORMULA YOU CITED ABOVE?

A19. We estimated operating revenues for the Subject Property by developing a revenue requirement specifically for the Subject Property. A utility's revenue requirement is a term of art used in utility rate regulation to reflect the amount of revenue necessary to run the utility, including the cost of operating and maintaining the utility. Generally speaking, the revenue requirement establishes the revenue the utility can reasonably expect to earn.

Q20. PLEASE DESCRIBE HOW YOU DEVELOPED THE FORECASTED REVENUE REQUIREMENT FOR THE SUBJECT PROPERTY.

A20. We developed the revenue requirement for the Subject Property over the next ten years based on estimated operations and maintenance ("O&M") expense, taxes, depreciation, and return on rate base. This modeled the typical manner of determining rates permitted for rate regulated utilities. We then assumed the owner of the Subject Property would be allowed rates to recover the revenue requirement. This implicitly assumes that the new owner would have new rates approved annually that reflect the forecasted change in rate base. Rate regulation does not typically allow for so frequent or immediate changes in

[8] "For assets such as a business whose life may be very long, the terminal value is the present value of the capitalized future value". American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets*, Fourth Edition, Glossary, p. 552.

rates, but this assumption allowed the benefits of increasing plant investments to be promptly recovered/reflected in rates and revenues.

Q21. WHAT IS RATE BASE?

A21. Rate base is the invested capital on which a rate regulated utility is allowed to earn a return. As previously mentioned, rate base is predominately composed of the OCLD value of the utility's plant in service, excluding contributed plant assets. However, there are miscellaneous other adjustments that may be appropriate, including additions to rate base for items such as cash working capital, prepayments, inventories, as well as deductions to rate base for items such as accumulated deferred income tax ("ADIT").

Q22. WHAT IS ADIT?

A22. ADIT arises from timing differences between the method of computing taxable income for reporting to the Internal Revenue Service and the method of computing income for regulatory accounting and ratemaking purposes. When a hypothetical buyer acquires new assets, it has the right to restart accelerated depreciation on the property. That accelerated depreciation effectively defers income taxes, which results in the accumulation of deferred income taxes. Under typical utility regulatory accounting rules, ADIT is deducted from rate base. Thus, in our analysis, rate base has been adjusted to account for the new owner (hypothetical buyer) having a different rate base than the balance currently reflected on PG&E's books when allocated to the Subject Property.

Q23. HOW DID YOU THEN CALCULATE A RETURN ON RATE BASE?

A23. We calculated a return on rate base as percent return multiplied by the rate base. The percent return was developed based on a weighted average cost of capital, assumed to reflect a return approved by the CPUC. Rate base was developed based on the OCLD for the Subject Property plant in service, plus an allowance for cash working capital and an inventory of spare equipment,[9] less an estimate of the ADIT as noted above. This analysis is detailed starting at page 4-5 of our Appraisal Report together with Attachment B.

Q24. HOW DOES DEVELOPMENT OF A RATE OF RETURN ON RATE BASE LEAD TO THE DEVELOPMENT OF FREE CASH FLOW?

A24. As discussed earlier, the forecasted revenue requirement for the Subject Property is assumed to equal estimated O&M expense, taxes, depreciation, and return on rate base. Revenue less operating expenses, including book depreciation, results in annual operating income for the next ten years. Income tax is then calculated based on the operating income and a combined state and federal income tax rate. However, for the calculation of income tax, tax depreciation was substituted for book depreciation.[10] After subtracting income taxes from operating income, book depreciation is added back to result in earnings before interest, depreciation and amortization ("EBIDA"). Depreciation is added back because it is a non-cash expense. Finally, annual capital investments and the setting aside of funds to account for changes in working capital are subtracted from EBIDA to determine free cash flow to the lenders of capital (debt and equity). This value, summed over 10 years, plus the addition of the calculated terminal value, discounted to a present value results in the Subject Property's value under the income approach.

---

[9] The RCN for the spare equipment was estimated by Advisian-Siemens.

[10] Tax depreciation allows for accelerated depreciation, which lowers the income tax amount in the near-term.

Q25. WHAT WAS THE RESULT OF THE INCOME APPROACH?

A25. Our estimate of the Subject Property's value based on the income approach is shown in Table 3.

Table 3
Income Approach Indicator of Value

Discounted Cash Flow Value	$ 2,374,024,000

Q26. DOES THE RESULT OF THE INCOME APPROACH HAVE IMPLICATIONS FOR THE COST APPROACH ANALYSIS?

A26. Yes. As discussed below, the income approach results in a value for the Subject Property that is less than the RCNLD adjusted only for physical deterioration. The income approach is also supported by the sales comparison approach, which indicates the presence of economic obsolescence. Therefore, the RCNLD must be reduced to be no higher than the DCF value shown in Table 3 above. This accounts for the reality that a willing buyer would not pay more than the income value of the property where, as here, the Subject Property is limited by rate regulation. We discuss this point in the discussion below of depreciation for economic obsolescence.

B. COST APPROACH

Q27. PLEASE DESCRIBE THE COST APPROACH.

A27. We developed two indicators of value under the cost approach. The first is RCNLD, which is defined as the cost of reproducing a similar new property at current prices with the same or closely related materials, less all forms of depreciation (physical deterioration, functional obsolescence, and economic obsolescence).[11] It is premised on the notion that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the Subject Property. As described in the American Society of Appraisers' textbook, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets,* the replacement cost approach:

> … begins with the current replacement or reproduction cost new of the property being appraised. The appraiser deducts for the loss in value caused by physical deterioration, functional obsolescence, and economic obsolescence. The logic behind the cost approach comes from the principle of substitution: a prudent buyer will not pay more for a property than the cost of acquiring a substitute property of equivalent utility.[12]

Q28. EXPLAIN THE DIFFERENCE BETWEEN REPLACEMENT COST NEW AND REPRODUCTION COST NEW.

A28. "Replacement cost new" is the current cost of a similar new property having the nearest equivalent utility as the property being appraised. "Reproduction cost new" is the current cost of reproducing a new replica of the property being appraised using the same, or closely similar, materials.[13] The two terms are abbreviated the same (as "RCN") and are often used interchangeably if changes in technology or regulation have not meaningfully changed the facilities used to provide service. In our appraisal, we used the Reproduction Cost New of the Subject Property estimated by Advisian-Siemens as the starting point in our cost approach analysis.

---

[11] Ibid., p. 32.

[12] American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets*, Fourth Edition, p. 32.

[13] Ibid., p. 34.

Q29. WHAT IS THE SECOND INDICATOR OF VALUE DEVELOPED UNDER THE COST APPROACH?

A29. The second indicator of value under the Cost Approach is OCLD. OCLD is equal to the original cost of the property when it was first put into service less the amount of accumulated depreciation based on the age, estimated service life, and estimated net salvage rate for the assets. The OCLD value is equivalent to the net plant in service or net book value of the assets. OCLD is a relevant indicator of value for rate regulated utility property, such as the Subject Property, because it is generally the largest component in rate base for ratemaking purposes. The OCLD value was used to estimate the rate base value of the Subject Property in the income approach analysis as described in the previous section of this testimony.

Q30. PLEASE PROVIDE AN OVERVIEW OF THE COST APPROACH ANALYSIS IN YOUR APPRAISAL REPORT (APPENDIX III).

A30. Attachment A to our appraisal report titled, Cost Approach: RCNLD and OCLD Analysis, shows the development of the RCNLD and OCLD indicators of value. Within Attachment A there are several tables, as listed in Table 4 below.

Table 4

Attachment A - Cost Approach: RCNLD and OCLD Analysis	
Table A-1	Summary of Cost Approach *
Table A-2	Summary of Reproduction Cost New Less Depreciation *
Table A-3	Summary of Original Cost Less Depreciation
Table A-4	Accumulated Net Salvage – Transmission Assets
Table A-5	Accumulated Net Salvage – Distribution Assets
Table A-6	Transmission Inventory
Table A-7	Distribution Inventory

* Before accounting for any functional or economic obsolescence

Each of these tables details the key elements for calculation of RCNLD and OCLD.

Q31. WHAT SOURCES OF INFORMATION DID YOU RELY UPON TO DEVELOP THE RCNLD VALUE OF THE SUBJECT PROPERTY?

A31. We utilized the asset list, current unit prices for different assets, and estimated installation year for the distribution and transmission plant assets, excluding real property (land, structures and site improvements), that comprise the Subject Property as developed by Advisian-Siemens on behalf of CCSF and described in the expert testimony of Nelson Bacalao and the engineering report prepared by Advisian-Siemens titled, *San Francisco Grid Procurement Engineering Services – Asset Valuation, Volumes I and II*, Project No. 308010-00232 (Appendices I and II to Advisian-Siemens Report). Advisian-Siemens provided its analysis to NewGen in detailed Excel spreadsheets, which we used to perform our RCNLD analysis. We reviewed the methodology and analyses developed by Advisian-Siemens to estimate the inventory quantities, age, condition and RCN of PG&E electrical distribution and transmission assets to be acquired and determined that we could reasonably rely on Advisian-Siemens' work product.

For the real property component of the Subject Property, we relied on data in the *Fair Market Valuation Statement of PG&E Transmission and Distribution Real Property*, *City and County of San Francisco, as of July 27, 2021*, prepared by Runde & Partners, Inc. (Appendix I to Testimony of Timothy P. Runde) on behalf of CCSF and described in the expert testimony of Timothy Runde on behalf of CCSF. We reviewed the methodology and analyses developed by Runde & Partners to estimate the FMV of real property assets to be acquired by the City and the qualifications and experience of Mr. Runde who performed the appraisal and determined that we could reasonably rely on Runde & Partners' appraisal report.

Q32. PLEASE DESCRIBE THE STEPS IN YOUR RCNLD ANALYSIS SHOWN IN ATTACHMENT A OF YOUR APPRAISAL REPORT.

A32. Tables A-6 and A-7 in Attachment A of our Appraisal Report list the transmission and distribution plant inventory, respectively, for the Subject Property. Tables A-6 and A-7 are voluminous because of all the inventory items in the Subject Property. Data in columns A through L show the inventory quantities, unit costs, and percentages for owner's costs and contingency and resulting RCN value that Advisian-Siemens developed. We assigned the FERC account numbers to assets (as shown in column D). Advisian-Siemens estimated the RCN value of the inventory in 3rd quarter 2022 dollars. Since the date of valuation in the proceeding is July 27, 2021, we trended the 2022 RCN values back to 2021 cost levels using the Handy Whitman Index of Public Utility Construction Costs, using the July index for 2021 and 2022 for the Pacific Region.[14] This is shown in columns M through P in Tables A-6 and A-7. Due to this adjustment, there is a difference in the NewGen and Advisian-Siemens RCN values.

The estimated installation year for the assets is shown in column P beginning on page 5 of 7 on Table A-6 for transmission plant and page 23 of 44 on Table A-7 for distribution plant. PG&E provided installation years for some, but not all, assets. Where installation year data was not available, Advisian-Siemens estimated an average installation year based on the information that was available. We reviewed Advisian-Siemens' age assumptions for the inventory, which appeared reasonable. If PG&E provides additional data for assets

[14] The Handy Whitman Index of Public Utility Construction Costs is an industry publication that is generally accepted in the industry for the estimation of construction costs.

with missing installation years, Advisian-Siemens may review this data and adjust its analysis, as appropriate.

Q33. PLEASE EXPLAIN THE TRENDED ORIGINAL COST CALCULATIONS SHOWN IN TABLES A-6 AND A-7 OF ATTACHMENT A TO YOUR APPRAISAL REPORT.

A33. In Columns X through AD of Tables A-6 and A-7 we used the Handy Whitman Index of Public Utility Construction Costs to trend the RCN values to original cost based on the estimated installation year for each asset. The trended original cost amounts by asset in Tables A-6 and A-7 were used to calculate the adjustment for net salvage, discussed later in our testimony.

Q34. WHAT WAS THE NEXT STEP IN YOUR RCNLD ANALYSIS?

A34. The next step in our analysis was to adjust the RCN value for all forms or causes of depreciation.

Q35. WHAT ARE THE BASIC FORMS OR CAUSES OF DEPRECIATION THAT ARE CONSIDERED IN THE COST APPROACH?

A35. There are three basic forms or causes of depreciation that the appraiser should consider in developing the RCNLD value of property:

1. Physical deterioration representing the loss in value or usefulness resulting from the wear and tear of an asset in operation and exposure to various elements.
2. Functional obsolescence representing the loss in value or usefulness caused by inefficiencies or inadequacies of the property itself, when compared to a more efficient or less costly replacement property that new technology might now allow.

3. Economic obsolescence representing the loss in value caused by factors external to the property.[15]

Q36. IN YOUR APPRAISAL, DID YOU REDUCE THE RCN VALUE OF THE SUBJECT PROPERTY FOR PHYSICAL DETERIORATION?

A36. Yes. We reduced the RCN value for physical deterioration and made an adjustment for net salvage (cost of removal). These calculations and the resulting RCN less physical deterioration value are shown in Attachment A to our Appraisal Report (Appendix III).

Q37. HOW DID YOU DETERMINE THE ADJUSTMENT FOR PHYSICAL DETERIORATION FOR DISTRIBUTION AND TRANSMISSION PLANT ASSETS?

A37. We determined the accumulated depreciation due to physical deterioration by applying the current depreciation parameters (average service life and survivor curve) approved by the CPUC for PG&E to determine the reserve ratio (i.e., percent of the asset cost that is depreciated) based on the age of each asset. This is shown in columns P through U in Tables A-6 and A-7. The adjustment to the RCN value for physical deterioration (Column V) is equal to the reserve ratio (column U) multiplied by the 2021 RCN value (column O), and the resulting RCNLD value (before adjustments for net salvage and functional and economic obsolescence) is shown in column W.

Q38. HOW DID YOU DETERMINE THE ADJUSTMENT FOR PHYSICAL DETERIORATION FOR REAL PROPERTY ASSETS?

A38. We relied on data from Mr. Runde's appraisal report to determine the amount of physical deterioration for real property assets. Attachment C of Mr. Runde's real property appraisal

---

[15] American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets*, Fourth Edition, pp. 48-49.

report specified the RCN and RCNLD (adjusted for physical deterioration) values for structural improvements and site improvements included in the Subject Property. (Land is not subject to physical deterioration so is not subject to such depreciation.) The RCN and RCNLD values for real property assets are included at the end of Table A-7, Distribution Inventory in our cost approach analysis.

Q39. EARLIER IN YOUR TESTIMONY YOU MENTIONED ADJUSTING THE RCNLD VALUE FOR NET SALVAGE. WHAT IS NET SALVAGE?

A39. "Net salvage" is equal to the gross salvage minus the cost of removal when property is retired.[16] Net salvage value can be either positive or negative. If gross salvage exceeds cost of removal, the net salvage is positive. On the other hand, if the cost of removal is greater than the gross salvage received upon retirement of an item of property, then the resulting net salvage value is negative. Net salvage rates are expressed as a percentage of original cost and are typically negative for most transmission and distribution plant accounts.

Utility depreciation rates approved by the CPUC include recovery of net salvage (cost of removal). For example, under the straight-line whole life method of depreciation, the original cost of property, adjusted for net salvage, is recovered over the average service life of the property, as shown in the formula below:

[16] Public Utility Depreciation Practices, August 1996, published by the National Association of Regulatory Utility Commissioners (NARUC), Washington, D.C., pp. 317 and 320.

$$D = \frac{1 - NS}{ASL}$$

where: D = annual depreciation accrual
NS = estimated net salvage ratio
ASL = average service life

Net salvage directly reduces (in the case of positive net salvage) or increases (in the case of negative net salvage) the dollars of plant to be depreciated over the service life of the plant. For example, if net salvage is a positive 10%, then the annual depreciation accrual rate over the plant's service life would need to recover 90% (i.e., 100% minus 10%) of the original cost of the plant. If net salvage is equal to negative 10%, then the annual depreciation accrual rate over the plant's service life would need to recover 110% (i.e., 100% plus 10%) of the original cost of the plant.

Q40. DESCRIBE THE ADJUSTMENT YOU MADE TO THE RCNLD VALUE FOR ACCUMULATED NET SALVAGE.

A40. For the RCNLD analysis, we calculated the estimated accumulated net salvage based on the trended original cost for the asset developed in Tables A-6 and A-7 times the current CPUC-approved net salvage rates based on the type of asset (i.e., FERC plant account) times the reserve ratio. The reserve ratio equals the percentage of total asset value that has been depreciated based on the age of the asset and the survivor curve and average service life approved by the CPUC to determine PG&E's depreciation rates. The adjustment for accumulated net salvage is developed in Tables A-4 and A-5 of Attachment A to our Appraisal Report (Appendix III).

Q41. HOW DID YOU DETERMINE THE "ORIGINAL COST" OF THE SUBJECT PROPERTY?

A41. We determined the original cost of the assets comprising the Subject Property primarily from original cost data provided by PG&E for assets located within CCSF.[17]

Q42. WERE ANY ADJUSTMENTS MADE TO THE ORIGINAL COST DATA PROVIDED BY PG&E?

A42. Yes, as illustrated in Table A-3 of Attachment A of our Appraisal Report, we made a few adjustments. First, the data provided by PG&E was as of December 31, 2020 and, separately, December 31, 2021. Given the date at which the appraisal was intended to reflect value (i.e., July 27, 2021), we took a simple average of the balances on these two dates to use in our analysis.

Further, given that the specific real property identified in the Subject Property does not align with the total real property owned by PG&E inside the City (as provided by PG&E), we relied on the appraised values for this property provided by Runde & Partners in place of the data provided by PG&E for FERC Accounts 350, 352, 360, 361, and 390 (which are the FERC Accounts for land, land rights, structures and improvements).

Additionally, because the Martin substation is not inside the City, it was not included in the original cost data provided by PG&E for assets inside the City.[18] Thus, we added the portion of the Martin substation that is included in the Subject Property to the original cost analysis.

---

[17] Appendix IV (Excerpted Supplemental PG&E response to DR-CCSF_04-Q04, attachment PGE000082649).

[18] Note: while PG&E did separately provide original cost data for the Martin substation as a whole, it understandably did not delineate between the facilities to be acquired by CCSF and the remaining facilities.

Finally, there was some specific spare equipment (underground network transformers and network protectors) identified by the Advisian-Siemens team, which is not in service and, therefore, would not be accounted for in PG&E's data for plant assets that are in service in the City, so we added these assets.

Q43. DID YOU INCLUDE COMMUNICATIONS EQUIPMENT?

A43. Yes. We included the communications equipment within CCSF, as provided by PG&E, in our analysis.

Q44. HOW DID YOU DETERMINE THE ORIGINAL COST OF FACILITIES THE CITY PROPOSES TO ACQUIRE AT THE MARTIN SUBSTATION?

A44. We used the trended original cost values for the Martin substation assets developed in Tables A-6 and A-7 in Attachment A of the Appraisal Report.

Q45. DESCRIBE HOW YOU ACCOUNTED FOR PHYSICAL DETERIORATION AND NET SALVAGE FOR THE OCLD ANALYSIS.

A45. The same reserve ratios (listed in Column U of Tables A-6 and A-7) were used to identify the physical deterioration for the original cost as was used for the RCN. When developing the OCLD, we assumed that the applicable net salvage rate for an asset is equal to the average historical net salvage rate based on the age of the asset and PG&E's historical net salvage rates over the time period. The average net salvage rate times the reserve ratio times the original cost, identified the dollar amount of accumulated net salvage. The net salvage calculations for transmission and distribution plant are shown in Tables A-4 and A-5, respectively.

Q46. WERE THERE ANY OTHER ADJUSTMENTS RELATED TO OCLD?

A46. Yes, it is possible for the net book value of assets to be zero dollars in rate base if the utility plant has been fully depreciated. In fact, it is possible for the book value to be negative due to negative net salvage (i.e., it costs more to remove the utility plant than it cost to install the plant originally). However, because we assume any asset still in service has value, we ensured that none of the OCLD values for any FERC Accounts were less than 10% of the original cost for the FERC Account, even if age or net salvage would suggest the book value could be zero or negative.

Q47. ARE THERE ANY OTHER IMPORTANT CONSIDERATIONS REGARDING YOUR ESTIMATED OCLD?

A47. Yes. Our RCN and original cost values include all relevant utility plant for the Subject Property, regardless of how PG&E came to own the property. Property contributed or funded by customers is generally not included in rate base, but we did not attempt to identify or remove these assets from our cost approach analyses. Thus, our analysis includes all assets owned by PG&E, even if they were donated to PG&E.

Q48. WHAT IS THE SUMMARY OF RESULTS FROM THE COST APPROACH?

A48. Table 5 below summarizes the RCN, RCNLD, Original Cost, and OCLD values developed in Attachment A of our Appraisal Report. However, it is important to note that the RCNLD value shown in Table 5 does not include any adjustment for functional or economic obsolescence.

Table 5

	Reproduction Cost New (2021$)	RCNLD [1]	Original Cost	OCLD
Distribution	$ 6,701,814,047	$ 2,577,031,889	$ 2,765,808,467	$ 1,125,512,945
Transmission	2,590,097,178	1,277,972,070	920,069,988	551,397,203
Real Property	596,959,367	491,727,489	139,443,179	108,357,122
Communications Equip	6,514,793	3,615,710	4,664,438	2,588,763
Spares	6,846,225	6,846,225	6,846,225	6,846,225
Total [2]	$ 9,902,231,610	$ 4,357,193,383	$ 3,836,832,297	$ 1,794,702,257

Source: Appendix III, Attachment A, Table A-1

Notes:

1) Before accounting for any functional or economic obsolescence
2) Reflects Martin Scenario 1

Q49. DID YOU MAKE ANY DEDUCTIONS TO YOUR ESTIMATED RCNLD VALUE FOR FUNCTIONAL OBSOLESCENCE?

A49. No, we did not make any deductions to the RCNLD value of the Subject Property for functional obsolescence. Functional obsolescence might be present if, for example, new technologies were available that allowed for more efficient operations. However, we are currently unaware of any functional obsolescence in the Subject Property.

Q50. DID YOU MAKE ANY DEDUCTIONS TO YOUR ESTIMATED RCNLD VALUE FOR ECONOMIC OBSOLESCENCE?

A50. Yes. Our appraisal analysis tested for the presence of economic obsolescence by comparing the income approach value and the RCNLD value before economic obsolescence and found that economic obsolescence does exist. “To determine the existence of economic obsolescence, the business enterprise value [i.e., income value] is compared with the depreciated replacement cost of the company’s productive assets. If the business enterprise value is less than the depreciated replacement cost of the company’s assets, then economic obsolescence typically exists."[19] Indeed, if the property's estimated value based on the "cost approach is significantly higher than the income approach (and even the sales comparison approach), then the appraiser should verify that all the depreciation was properly quantified, especially economic obsolescence."[20] Economic obsolescence might take the form of any number of conditions external to the property[21] but, for utility property, economic obsolescence due to rate regulation is of primary concern.

Q51. WHY IS IT APPROPRIATE FOR THE DEPRECIATION OF THE SUBJECT PROPERTY TO CONSIDER RATE REGULATION AS A FORM OF ECONOMIC OBSOLESCENCE?

A51. The fact that the CPUC restricts PG&E's earnings to a reasonable rate of return on the assets included in rate base is an "external factor" that must be considered. Under utility rate regulation, the utility is allowed to charge rates that produce revenues equal to the utility's total revenue requirement including a reasonable rate of return on rate base as determined by the CPUC. The largest component of rate base is the OCLD value of the utility's plant in service. As a result, the income value of rate regulated utility property is tied to the OCLD value of the utility's plant in service since this is the value of the utility's

---

[19] Shannon P. Pratt, *Valuing a Business, The Analysis and Appraisal of Closely Held Businesses*, Fifth Edition, p. 888.

[20] American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets*, Fourth Edition, p. 176.

[21] Examples of external factors include economics of the industry; availability of financing; loss of material and/or labor source; passage of new legislation; changes in ordinances; increased cost of raw materials, labor or utilities (without an offsetting increase in product price); reduced demand for the product; increased competition; inflation or high interest rates; or similar factors. (American Society of Appraisers, *Valuing Machinery and Equipment*, Fourth Edition, pp. 48-49).

investment on which it is allowed to earn its authorized rate of return or profit. An informed buyer would not be willing to pay an amount more than the income value of the property because the buyer would not be able to earn a reasonable return on its investment.

Q52. HOW DID YOU DETERMINE THE ADJUSTMENT FOR ECONOMIC OBSOLESCENCE?

A52. The adjustment for economic obsolescence is based on the assessment of the present value of the future earnings from the Subject Property under the income approach compared to the RCNLD after deducting physical deterioration and functional obsolescence. As a rate regulated utility, the value of the Subject Property must be calibrated based on its ability to earn profits from the ownership and operation of the utility property. Therefore, the adjustment for economic obsolescence is equal to the difference between the income approach indicator of value and the RCNLD value after deducting physical deterioration and functional obsolescence.

Q53. IS THAT WHY YOU SHOW RCNLD FOR THE SUBJECT PROPERTY ON TABLE 1 AS $2,374,024,000?

A53. Yes. For the reasons discussed, the RCNLD figure must be adjusted downward to reflect the negative impact on income imposed by CPUC rate regulation. Because the RCNLD of the Subject Property can be no higher than its ability to earn income, the amount in excess represents economic obsolescence that must be subtracted to develop RCNLD. That is the basis for the $2,374,024,000 RCNLD amount shown in Table 1 of our testimony.

C. <u>SALES COMPARISON APPROACH</u>

Q54. PLEASE DESCRIBE THE SALES COMPARISON APPROACH.

A54. The sales comparison approach involves review of recent sales of similar facilities between a willing buyer and a willing seller, who are unrelated, as an indication of the market price for such properties. The guideline sale transactions method under the sales comparison approach is primarily applicable to property that is readily substitutable and where several similar type properties have recently been sold. Caution must be exercised when using the comparable sales method as an indicator of value for utility property. Normally, the appraiser will, when necessary, make adjustments to the guideline sale transactions in order to correlate the sales price to the characteristics of the subject property. However, there are many factors that can influence sales price including, among others, market area, age, condition, and other considerations that may be reflected in the sales price. Each party's motivation can affect the negotiation and the terms of the sale. Strategic objectives are the driving motivator for some sales. These objectives are often kept confidential and are not available to an appraiser for evaluation. For this reason, we generally use the sales comparison approach as a test of the reasonableness of values produced by the cost and income approaches.

Q55. WHAT SALES TRANSACTIONS DID YOU USE IN YOUR COMPARABLE SALES ANALYSIS?

A55. Table 6 below shows select sales transactions involving electric utility distribution property that occurred from 2011 through 2022. All of the sales shown in Table 6 were negotiated sales and did not involve the exercise of eminent domain. There is a wide variation in the size, location, and type of plant (e.g., some sales include generation plant) for these sales, and no attempt was made to adjust the sales to correlate with the characteristics of the Subject Property. More information regarding the guideline sale transactions is provided in Attachment D of our Appraisal Report.

Table 6
Electric Utility Sale Transactions

No.	Year	State	Buyer	Seller	Purchase Price	Net Plant	Purchase Price/ Net Plant
1	2011	CA	California Pacific Electric Co. (Liberty Energy)	Sierra Pacific Power Co.	136,418,000	$ 123,599,000	1.10
2	2011	OH	AES Corporation	DPL, Inc. (Dayton Power & Light)	$ 4,719,000,000	$ 2,965,600,000	1.59
3	2012	NH	Liberty Energy NH	Granite State Electric Co.	$ 83,000,000	$ 81,380,000	1.02
4	2015	IA, MN	Southern Minnesota Energy Cooperative	Interstate Power & Light	$ 129,000,000	$ 105,189,000	1.23
5	2017	MO, KS, OK, AR	Liberty Utilities Co. (Algonquin)	The Empire District Electric Company	$ 2,348,510,000	$ 1,919,010,000	1.22
6	2019	TX	AEP Texas, Inc.	Oncor Electric Delivery Company, LLC	$ 17,956,000	$ 17,956,000	1.00
7	2019	FL	NextEra Energy	Gulf Power Company	$ 5,657,000,000	$ 3,605,426,000	1.57
8	2019	ME	ENMAX	Emera Maine	$ 1,295,000,000	$ 1,066,820,818	1.21
9	2020	TN	Middle Tennessee Electric Membership Corporation	Murfreesboro Electric Department	$ 202,000,000	$ 152,382,078	1.33
10	2020	AK	Chugach Electric Association	Anchorage Municipal Light & Power	$ 986,000,000	$ 703,166,000	1.40
11	2020	TX	JP Morgan Chase	El Paso Electric Company	$ 4,370,650,000	$ 3,120,858,000	1.40
12	2022	RI	PPL Corporation	Narragansett Electric Company (National Grid)	$ 5,320,000,000	$ 3,471,757,000	1.53
						Mean	1.30

While many of the sales transactions in Table 6 vary in size compared to the Subject Property, examining the ratio of purchase price to net plant (OCLD) provides insight into the valuation of rate regulated property in willing buyer/willing seller transactions. The average (mean) ratio results in a purchase price equal to 1.30 times net plant. Most of the sales are within plus or minus one standard deviation from the mean, i.e., 1.10 to 1.50 times net plant, which corresponds to a range of value under the sales comparison approach for the Subject Property of approximately $1.97 billion to $2.70 billion based on an OCLD (net plant) value of electric plant of $1,794,702,000 (rounded).

Q56. WHAT ARE THE RESULTS OF YOUR SALES COMPARISON APPROACH ANALYSIS?

A56. The indication of value for the Subject Property from the sales comparison approach is shown in Table 7. This is based on the average (mean) ratio of 1.30 times net plant resulting from the transactions evaluated applied to the OCLD of the Subject Property.

Table 7
Sales Comparison Approach Indicator of Value

Based on Average Ratio of Purchase Price to Net Plant	$ 2,334,403,000

VI. MAPS, DRAWINGS AND RECORDS

Q57. DOES THE SUBJECT PROPERTY VALUED IN YOUR APPRAISAL INCLUDE MAPS, DRAWINGS AND RECORDS?

A57. Yes. The Subject Property identified in Section 3 of our Appraisal Report (Appendix III) includes 1) existing maps, drawings, operation and maintenance logs, and other engineering and operations records for the assets acquired, and 2) PG&E electric utility customer billing records, by customer and rate schedule, for customers located within the City. The cost of maps and drawings of plant are capitalized costs that are included in the construction cost of a project. Maintenance and inspection records are part of ongoing operations and maintenance expense that is paid for by ratepayers and are part of the utility's business. In addition, utilities are required by the CPUC to keep accurate maintenance and inspection records as part of their normal business operations.

Under the willing buyer/willing seller principle, which is embodied in the definition of fair market value, the seller would be willing to provide maps, drawings and records that pertain to the Subject Property as part of the sale transaction. The maps, drawings and records pertaining to the Subject Property have little to no value to anyone other than the owner of the Subject Property. In situations where the seller needs to retain maps, drawings and records for the Subject Property, it may be appropriate for the buyer to reimburse the seller for the cost to produce copies of maps, drawings and records pertaining to the Subject Property.

It is highly probable that maps, drawings and records were included in the utility sales transactions (shown in Table 6) used in the sales comparison approach, the results of which support the income approach indicator of value. Therefore, no additional value should be added to the Fair Market Value of the Subject Property for maps, drawings and records because they are already included in the sales comparison approach and income approach indicators of values.

VII. FAIR MARKET VALUE

Q58. PLEASE DESCRIBE YOUR DETERMINATION OF FAIR MARKET VALUE FOR THE SUBJECT PROPERTY.

A58. The definition of Fair Market Value used in this appraisal refers to the highest price on the date of valuation that would be agreed to by a willing seller and a willing buyer.[22]

[22] California Code of Civil Procedure Section 1263.320.

However, this does not imply that the Fair Market Value of the Subject Property is equal to the highest indicator of value developed in the appraisal. We considered and evaluated all three generally accepted approaches to valuation (cost, income, and sales comparison approaches) in developing our opinion of the Fair Market Value of the Subject Property. Under the principle of substitution, an informed buyer would pay no more than the cost of producing a substitute property with the same utility as the Subject Property. However, an informed buyer would also pay no more than the income value of the property. As discussed earlier, the effect of utility rate regulation is an important consideration in valuing public utility property. Under standard ratemaking procedures, rate regulated utilities are allowed the opportunity to earn a fair and reasonable rate of return on their rate base (predominately composed of the OCLD value of the non-contributed plant assets). Thus, the income value for rate regulated utility property is closely tied to its rate base value since this is the value of the utility's investment on which it is allowed to earn its authorized rate of return.

An informed buyer would not be willing to pay a price for the Subject Property that exceeds the income value of the property. Therefore, the RCNLD value without proper adjustment for economic obsolescence is not a relevant indicator of the value for the Subject Property. We tested for the presence of economic obsolescence by evaluating the income approach value and determined that economic obsolescence does exist for the Subject Property.

The sales comparison approach has some weaknesses previously identified that bear on its reliability in the determination of Fair Market Value for utility property, but the results of the sales comparison approach generally support the income value for the Subject Property.

After consideration of the indicators of value developed using generally accepted approaches to valuation, given the relative strengths and weaknesses of each and the analyses and assumptions used therein, we are of the opinion that the Fair Market Value of the Subject Property (under Martin Scenario 1) as of July 27, 2021 is $2,374,000,000 as indicated by the income approach (rounded to the nearest million).

Q59. ARE YOU AWARE THAT MR. BEICKE, THE CO-HEAD OF POWER UTILITIES AND INFRASTRUCTURE AT JEFFERIES LLC HAS PROVIDED AN OPINION IN THIS PROCEEDING THAT VALUES THE SUBJECT PROPERTY SOMEWHAT HIGHER THAN YOUR APPRAISAL?

A59. Yes, we have seen the testimony of Mr. Beicke from the investment bank, Jefferies LLC. Mr. Beicke uses variations on the income and sales comparison approaches, which yield a range of results that vary from the results we developed using the cost, income and sales comparison approaches. His analysis seems to be indicative of the approach more typically done by investment banks.

VIII. MARTIN SUBSTATION

Q60. WHAT VARIATION IN FAIR MARKET VALUE RESULTS FROM THE THREE SCENARIOS YOU EXAMINED FOR THE MARTIN SUBSTATION?

A60. Table 8 below summarizes the impact of the three scenarios we examined on the total value of the Subject Property under each of the three valuation approaches.

Table 8
Impact of Martin Scenarios on Total Valuation of Subject Property

	Scenario 1 Base Case	Scenario 2	Scenario 3 No Martin
Cost Approach:			
Reproduction Cost New	$ 9,902,232,000	$ 9,807,603,000	$ 9,677,603,000
Less: Physical Deterioration and Net Salvage	(5,545,038,000)	(5,522,381,000)	(5,498,878,000)
Less: Functional Obsolescence	-	-	-
Less: Economic Obsolescence	(1,983,170,000)	(1,965,771,000)	(1,981,657,000)
Reproduction Cost New Less Depreciation (RCNLD)	$ 2,374,024,000	$ 2,319,451,000	$ 2,197,068,000
Original Cost	$ 3,836,832,000	$ 3,785,159,000	$ 3,698,865,000
Less: Physical Deterioration and Net Salvage	(2,042,130,000)	(2,027,176,000)	(2,016,461,000)
Original Cost Less Depreciation (OCLD) – Rate Base	$ 1,794,702,000	$ 1,757,983,000	$ 1,682,404,000
Income Approach:			
Discounted Cash Flow	$ 2,374,024,000	$ 2,319,451,000	$ 2,197,068,000
Sales Comparison Approach:			
Guideline Sale Transactions	$ 2,334,403,000	$ 2,286,642,000	$ 2,188,335,000
Estimated Fair Market Value of Subject Property	**$ 2,374,000,000**	**$ 2,319,000,000**	**$ 2,197,000,000**
Difference in FMV from Scenario 1		**($ 55,000,000)**	**($ 177,000,000)**

IX. CONCLUSION

Q61. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A61. Yes, it does.

STATEMENT OF QUALIFICATIONS – NANCY HELLER HUGHES

Q1. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A1. My name is Nancy Heller Hughes. I am an Executive Consultant at NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 20014 Southeast 19th Street, Sammamish, Washington 98075.

Q2. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A2. I graduated from the University of Chicago with a bachelor's degree in Business and Statistics in 1977. I received a master's degree in Business Administration at the University of Chicago in 1978.

Q3. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A3. From 1977 through 1982, I was employed by Ernst & Ernst (now Ernst & Young), working primarily on telecommunications regulatory matters before the Federal Communications Commission. From 1982 through 2012, I was employed by R. W. Beck, Inc. (R. W. Beck), an engineering and consulting firm that provided services in the energy and water resources utility industry. I held positions with increasing responsibilities and was an owner in R. W. Beck until July 2009, when R. W. Beck was acquired by Scientific Applications International Corporation ("SAIC"). In June 2012, I left SAIC to form my own independent consulting firm called Heller Hughes Utility Consulting, LLC. In September 2012, I became an owner and founding member of NewGen. In April 2020, I retired as an owner in NewGen and continue to work on projects in my present role as a Principal at NewGen.

A substantial part of my work involves depreciation and valuation issues. I have testified on depreciation, valuation, and other rate and regulatory issues before the Federal Energy Regulatory Commission, state regulatory commissions, and courts of law.

Q4. DO YOU HAVE ANY PROFESSIONAL CERTIFICATIONS?

A4. Yes. I am an Accredited Senior Appraiser ("ASA") of public utility property certified by the American Society of Appraisers. I am also a Certified Depreciation Professional ("CDP") certified by the Society of Depreciation Professionals. Additional information regarding my professional experience is provided in my attached résumé (Appendix I).

STATEMENT OF QUALIFICATIONS – GRANT RABON

Q1. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A1. My name is Grant Rabon. I am a Partner at NewGen Strategies and Solutions, LLC ("NewGen"), a management and economic consulting firm specializing in the utility industry. I work out of the Austin office of NewGen located at 8140 North Mopac Expressway, Suite 1-240, Austin, Texas 78759.

Q2. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A2. I was awarded a Bachelor of Science degree in Chemical Engineering from Texas A&M University in College Station, as well as a Master of Business Administration from the University of Texas at Austin.

Q3. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A3. In 2005, I began working at R. W. Beck, Inc. as a consultant and continued there until July 2009, when R. W. Beck was acquired by Scientific Applications International Corporation ("SAIC"). SAIC changed the name of the division I worked in to Leidos and then I left in July 2013 to join NewGen as a Senior Consultant.

Since 2005, I have been assisting utilities with the conduct of cost of service and rate design studies, utility appraisals, financial feasibility studies, and other management consulting engagements for electric, natural gas, water, wastewater, and solid waste utilities. Additional information regarding my professional experience is provided in my attached résumé (Appendix II).

Q4. DO YOU HAVE ANY PROFESSIONAL CERTIFICATIONS?

A4. Yes. I am an Accredited Senior Appraiser ("ASA") of public utility property certified by the American Society of Appraisers.

Docket:	P.21-07-012
Exhibit No.:	____________
Date Served:	April 10, 2023
ALJ:	R. Lirag
Witnesses:	Scott Beicke

PREPARED

DIRECT TESTIMONY

OF

SCOTT BEICKE

ON BEHALF OF

THE CITY AND COUNTY OF SAN FRANCISCO

APRIL 10, 2023

TABLE OF CONTENTS

I. INTRODUCTION

Q1. Please state your name and title.

A1. My name is Scott Beicke. I am a Managing Director and Co-Head of Jefferies' Americas Power, Utilities & Infrastructure Group.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of the City and County of San Francisco ("CCSF").

II. QUALIFICATIONS AND EXPERIENCE

Q3. Please describe your background and expertise relevant to your testimony in this case.

A3. I have over 20 years of investment banking and capital markets experience, with a focus on Mergers and Acquisitions ("M&A"), and debt and equity expertise across regulated utilities, power, renewables and energy transition, as well as select other "core" (essential infrastructure assets that deliver resilient cash flows from a protected market position) and "core plus" (assets that mimic the characteristics of "core" classic infrastructure investments that have a higher risk profile) infrastructure sectors. This work includes extensive valuation experience across the utilities and power space.

Immediately prior to joining Jefferies in 2018, I spent approximately 15 years at Morgan Stanley where I served as a Managing Director in the firm's Global Power & Utility Group.

I graduated with a Bachelor of Arts in Economics from Cornell University and earned an MBA in Finance & Accounting (with high honors) from the University of Chicago Graduate School of Business.

Q4. Please describe Jefferies and its work that is relevant to the topic(s) in this proceeding.

A4. Jefferies is a U.S.-headquartered full service, integrated investment banking and securities firm. Jefferies is the largest independent, global, full-service investment bank headquartered in the U.S. Our firm provides a full range of investment banking, advisory, sales and trading, research and wealth management services across all products in the Americas, Europe and Asia.

Jefferies serves as investment banking advisor to CCSF in connection with this proceeding.

Q5. Was this testimony prepared by you or under your direction?

A5. Yes, this testimony and the underlying analysis supporting it were prepared by our team at Jefferies under my direction.

III. PURPOSE OF TESTIMONY

Q6. Please describe the purpose of your testimony.

A6. The purpose of my direct testimony is to provide an estimated range of values a Hypothetical Buyer (defined herein) would be willing to pay ("Hypothetical Market Value") for the assets currently owned by Pacific Gas and Electric Company ("PG&E") that the City would need to acquire to provide electric service to customers in CCSF, as identified in the engineering report titled, *San Francisco Grid Procurement Engineering Services – Asset Valuation, Volumes 1 and 2,* prepared by Advisian, Worley Group with Siemens Industry, Inc. (Appendix 1 to the Testimony of Nelson Bacalao). This portion of the PG&E electric system will be referred to as the "Subject Property" or the "Assets" in our testimony. The Subject Property includes Assets for transmission, distribution, structures and improvements, and land. We define a "Hypothetical Buyer" as any acquiror that would purchase these Assets in a competitive marketplace and that intends to keep these Assets as regulated and rate-based Assets, subject to the jurisdiction of the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC").[1]

Q7. What qualifications and limitations are important to be aware of regarding your testimony?

[1] Though PG&E's recovery of its transmission costs is largely determined by FERC, this testimony references CPUC regulation and uses input assumptions provided to us regarding authorized cost recovery that are based on CPUC-authorized amounts.

A7. The information contained in this testimony is based solely on publicly available information or information furnished to Jefferies by CCSF or their consultants. Jefferies has relied, without independent investigation or verification, on the accuracy, completeness and fair presentation of all such information and the conclusions contained herein are conditioned upon such information (whether written or oral) being accurate, complete and fairly represented in all respects.

Jefferies, its affiliates and its and their respective employees, directors, officers, contractors, advisors, members, successors and agents shall have no liability with respect to any information or matter contained herein.

This document is not a product of any Jefferies research department and should not be construed as a research report.

This testimony does not constitute and should not be construed as a fairness opinion of Jefferies and should not be relied on by any person as such.

Neither Jefferies nor any of its affiliates is an advisor as to legal, tax, accounting or regulatory matters in any jurisdiction.

IV. SUMMARY OF CONCLUSIONS

Q8. What is your recommended estimate of the Hypothetical Market Value for the Subject Property?

A8. Subject to the assumptions made, procedures followed, factors considered and qualifications and limitations discussed below, our analysis concludes that $2.5 billion to $3.0 billion reflects a reasonable range for the Hypothetical Market Value of the Subject Property.

V. GENERAL METHODOLOGY AND APPROACH

Q9. Please generally describe the methodology you would use if advising a Hypothetical Buyer of assets similar to the Subject Property.

A9. Jefferies' approach to the valuation of the Subject Property from the viewpoint of a Hypothetical Buyer is consistent with the principles and methods that underpin a traditional corporate acquisition valuation. These methodologies include a discounted cash flow ("DCF") Analysis, comparable companies trading multiples analysis ("Comparable Trading Multiples Analysis") and precedents transactions analysis ("Precedents Analysis"), each described further below.

The DCF Analysis would serve as the foundation for the valuation and be analyzed on a levered[2] and unlevered[3] basis. The other valuation methodologies, including Comparable Trading Multiples Analysis and Precedents Analysis, provide valuation reference points that give insight to how the equity market values similar assets/companies as of the valuation date and how assets/companies that have transacted previously indicate value. Taken into consideration with the DCF Analysis, they help a Hypothetical Buyer triangulate on the Hypothetical Market Values of the Subject Property.

It is important to note that there is no single approach to arriving at a valuation. As a result, my testimony is set up to demonstrate the spectrum of approaches a Hypothetical Buyer would likely consider when evaluating a transaction, and the range of hypothetical values each approach would indicate. We then provide a range of Hypothetical Market Values a Hypothetical Buyer would consider based on a weighted average calculation of each valuation approach.

Q10. How would a potential buyer view the Subject Property that is the subject of this proceeding?

A10. A Hypothetical Buyer likely would view the Subject Property and the regulatory landscape associated with it and ascribe value to these Assets largely on the basis of their ability to earn a regulated rate of return.

A Hypothetical Buyer's views of the Assets would differ depending on a variety of factors, including the specific characteristics of the Assets themselves, as well as the Hypothetical Buyer's plans for the Subject Property. Fundamentally, the age of the Assets and their current Rate Base value, as well as the prospects for future Rate Base growth, would serve as the

[2] A levered DCF looks at the amount of cash flow a business has after it has met all of its debt obligations.

[3] An unlevered DCF looks at the amount of cash flow a business has before it has met its debt obligations.

foundational elements of a prospective valuation. A Hypothetical Buyer would need to understand with granularity the regulatory and tax depreciation schedules for the Assets being purchased, form a view on the future capital expenditure ("CapEx") needs, and develop expectations of whether the CPUC would authorize recovery of those CapEx needs. CapEx and depreciation assumptions will materially influence valuation. Lastly, other considerations about unique or specific risks or costs (for example these Assets having gone through bankruptcy twice as well as any potential future wildfire exposure), existing non-bypassable charges, and any exit fees would need to be factored into a final determination of value.

Q11. Please explain the effect of rate regulation on your analysis of what a Hypothetical Buyer might offer for the Assets.

A11. Rate regulation is a key component of how a Hypothetical Buyer would analyze potential value of the Subject Property. As discussed above, the core assumption underlying our analysis is that any Hypothetical Buyer would be acquiring the Subject Property and customer base subject to CPUC regulation materially consistent with how PG&E, as the current owner, is currently regulated.

Q12. What characteristics of the Assets would you consider in your analysis for a Hypothetical Buyer?

A12. We would consider the age and condition of the Assets, particularly as these considerations relate to previous and remaining depreciation, the need for upgrades and modernization, and similar characteristics that would impact future Rate Base, the authorized return on Rate Base and expected cash flows.

Q13. What potential impact would severance/exit fees have on a Hypothetical Buyer's valuation?

A13. Any severance damages or exit fees attached to the Subject Property would likely serve as a direct deduction from the implied range of Hypothetical Market Values in our analysis. Given these have not been provided to us, the range of Hypothetical Market Values included here does not include such costs, though they would reduce a Hypothetical Buyer's perspective on value.

Q14. Would a Hypothetical Buyer consider what it might cost to replace the subject Assets with the construction of new facilities?

A14. We do not believe a Hypothetical Buyer would focus on the direct cost to replace the Assets with the construction of the facilities ("Replacement Cost"). Because the expected Free Cash Flow ("FCF") derived from these Assets would be a function of their regulated returns, the current value of these Assets is driven by their Rate Base value and ability to earn a regulated return, not their physical Replacement Cost. The Assets would be acquired in their current condition and state, subject to their existing Rate Base value. PG&E's ratepayers have been paying for these Assets over time as they have been depreciated within Rate Base. Using Replacement Cost as a driver of value would only make sense if a Hypothetical Buyer expected the Replacement Cost to establish a new Rate Base and influence regulated returns and resulting cash flows. Because establishing Rate Base at a higher value essentially would require ratepayers to pay twice for the same assets, we do not believe a Hypothetical Buyer would assume the CPUC would authorize them to recover Replacement Cost in rates.

Q15. What valuation date does your analysis assume? Does your assessment account for conditions in the financial markets as of the date of the valuation?

A15. Jefferies' valuation assumes a valuation date of July 27, 2021, which is the date CCSF filed its petition for valuation of PG&E's Assets, initiating proceeding P.21-07-012. The analysis accounts for conditions in the financial markets as of this date. Conditions in the financial markets as of this date influence several elements of our valuation analysis, including the discount rates used for the DCF Analysis, the trading multiples applied to the Comparable Trading Multiples Analysis, and the date through which valuation multiples of precedent transactions were included for the Precedents Analysis.

Q16. What information about the Subject Property and PG&E's service territory within the boundaries of CCSF did you rely upon in reaching the conclusions in your testimony?

A16. As the starting point in our analysis, Jefferies relied upon data provided by and contained in the NewGen Strategies & Solutions ("NewGen") report prepared on behalf of CCSF and titled, *Appraisal of PG&E Electrical Distribution and Transmission Facilities in* *the City of San Francisco* (2023) (Appendix III) to the Testimony of Nancy Heller Hughes and Grant Rabon) ("NewGen Report"), for assumptions on: (i) starting net utility plant,(ii) remaining life of the Assets, (iii) the CapEx forecast, and (iv) net working capital ("NWC").[4]

Q17. Did you conduct your own assessment or evaluation regarding the information about PG&E's Assets?

A17. Jefferies did not conduct any independent evaluation or appraisal of any of the assets or underlying information assumed about the Subject Property. We assumed and relied upon the accuracy and completeness of the information we were provided, without independent verification of such information.

VI. KEY INPUTS AND COMPONENTS OF THE VALUATION ANALYSIS

a. The Rate Base Model

Q18. Please describe how you would typically model the cash flows for a Hypothetical Buyer?

A18. If advising a Hypothetical Buyer on the acquisition of assets similar to the Subject Property, Jefferies would rely on the Hypothetical Buyer's inputs and assumptions on all key parameters to construct a pro forma financial model for a regulated utility (the "Rate Base Model") to provide the foundation of our valuation analysis. The Rate Base Model would forecast, among other things, Rate Base, Authorized Net Income, Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA"), and FCF (these and other terms and abbreviations are briefly defined in the attached Glossary).

Q19. Please describe how you developed the Rate Base Model for the Subject Property. What key inputs and assumptions were included, and how were they derived?

A19. To develop the pro-forma model which would contain the Subject Property, we constructed a Rate Base Model that builds from Rate Base to Authorized Net Income, EBITDA and FCF.

[4] Does not reflect minor updates that were included in the NewGen Report after the analysis was completed.

Table 1 below summarizes the key inputs, sources and assumptions used in constructing the Rate Base Model:

Table 1: Key Inputs and Assumptions Summary

Input	Description	Source
Rate Base	The 2021 year-end Rate Base (first year of the analysis) was calculated as the ending 2021 balance of net utility plant from the NewGen report, to which we f added ADIT and NWC . For each year thereafter, the Rate Base was grown by the annual net increase in CapEx over Book D&A, adjusting for ADIT and the change in NWC. Moving forward, the beginning balance of Rate Base is equal to the ending balance of the prior year.	NewGen Report, Net Utility Plant (Table A-1) NewGen Report, NWC (Table B-2)
CapEx	This represents the annual capitalized investment in the Subject Property. Annual CapEx is based on figures provided in the NewGen Report through 2030 and assumes continued CapEx growth of 2.8% thereafter. Future CapEx spend was depreciated using a 20-year MACRS schedule for tax purposes, and a 30-year straight-line schedule for book purposes.	NewGen Report, CapEx (Table B-3)
Book Depreciation & Amortization ("Book D&A")	Book D&A represents the reduction in value of the assets included in Rate Base throughout their useful lives. Assets included at the time of acquisition were depreciated straight-line based on their assumed remaining useful lives based on NewGen's estimated asset age and useful life projection (number of years). For example,	NewGen Report, Existing Asset Age & Useful Life (Table A-3)

	if an asset is 15 years old and has a 32-year useful life, net utility plant was divided by 17 to calculate an annual depreciation amount that was applied each year until the asset was fully depreciated. New assets added to Rate Base from July 27, 2021, through December 31, 2031 (the "Forecast Period") via CapEx spend were depreciated on a 30-year straight line schedule for book purposes. Land and spares were not depreciated, in accordance with utility accounting standards.	
Tax Depreciation & Amortization ("Tax D&A")	For tax depreciation purposes, we took the net utility plant of the Assets acquired, excluding land and spares,[5] and depreciated them using a 20-year Modified Accelerated Cost Recovery System ("MACRS")[6] schedule. The value of goodwill (purchase price minus net utility plant) was depreciated on a straight-line over 15 years.	
Accumulated Deferred Income Tax ("ADIT")	ADIT is an account to track the temporary timing differences that arise given accelerated Tax D&A schedules compared to the straight-line Book D&A used for rate-making purposes. ADIT began with a zero balance, and is built through time based on any deferred tax liabilities ("DTL") or deferred tax assets ("DTA") incurred. By the end of the	

[5] Spare parts inventory is essential to ensuring reliability for the Subject Property. Spares are not depreciated since they are not being used and are not deemed in service.

[6] MACRS is an IRS-approved tax depreciation schedule that allows an investor to depreciate the basis of an asset more heavily in the near term. This schedule influences the effective taxes that the investor will need to pay for the Assets each year. A MACRS schedule is more front-weighted compared to a straight-line schedule that uses equivalent depreciation each year.

	depreciation life cycle for an asset, the ADIT is zero.	
Net Working Capital ("NWC")	The primary components of working capital are materials and supplies, inventory, and cash. The inventory of materials and supplies are needed to support the maintenance and construction activities of utilities. Firms require working cash to maintain the business and account for timing differences between receipt of Accounts Receivable and payment of Accounts Payable. NWC is set at 45 days of forecasted O&M and Taxes other than Income Taxes ("TOTIT").	NewGen Report, NWC (Table B-2)

- PG&E's currently authorized capital structure and respective authorized returns were applied to each year's projected Rate Base to calculate interest expense, preferred stock distributions and Authorized Net Income. For example, Rate Base times the authorized equity portion times the authorized equity return is equal to the Authorized Net Income.
- To each year's projected Authorized Net Income, we applied the combined effective federal and state tax rate of 27.98% (the "Tax Rate") to arrive at Earnings Before Taxes ("EBT").
- To each year's projected EBT, we added authorized interest expense to arrive at Earnings Before Interest and Taxes ("EBIT").
- Then, to each year's projected EBIT we added Book D&A and the Preferred Stock Dividend to arrive at EBITDA.

Authorized equity capitalization and authorized return on equity are approved by CPUC. As of the date of the valuation, PG&E's equity capitalization and return on equity were set at 52.00% and 10.25%, respectively.[7] For our analysis we have assumed that the same returns

[7] Source: PG&E "Cost of Debt Update in Compliance with OP 6 of Decision 20-05-053".

and capitalization structure would apply to a Hypothetical Buyer, see Table 2. Jefferies assumed that these capitalization percentages and returns remain constant throughout the Forecast Period and for purposes of calculating TVs. We assumed that customer rates are perfectly aligned with required return and actual expenses. Said differently, we assumed perfect ratemaking.

Table 2: Authorized Returns

Form of Capital	**2021 Authorized Capitalization**	**2021 Authorized Return**
Equity	52.00%	10.25%
Preferred Stock	0.50%	5.52%
Long-Term Debt	47.50%	4.17%

Q20. What are the Authorized Net Income and EBITDA results from your analysis using the Rate Base Model?

A20. The Authorized Net Income and EBITDA, after all adjustments, are shown in Table **3** below.

Table 3: Authorized Net Income and EBITDA Build

	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E
$mm (unless otherwise noted)											
Total Rate Base											
Beginning Balance	1,744	1,819	1,856	1,894	1,936	1,978	2,020	2,062	2,105	2,146	2,192
(+) Capex	137	141	145	149	153	157	162	166	171	176	181
(-) D&A	(89)	(93)	(98)	(97)	(102)	(107)	(113)	(118)	(124)	(119)	(116)
(-)/+ Deferred Tax Liability / Asset	2	(11)	(10)	(10)	(9)	(8)	(7)	(6)	(7)	(10)	(14)
(+) Change in NWC	25	0	0	0	0	0	0	0	0	0	1
Ending Balance	1,819	1,856	1,894	1,936	1,978	2,020	2,062	2,105	2,146	2,192	2,244
Capital Structure											
Debt Base	864	882	899	919	939	959	980	1,000	1,019	1,041	1,066
Equity Base	946	965	985	1,006	1,028	1,050	1,072	1,094	1,116	1,140	1,167
Preferred Stock Base	9	9	9	10	10	10	10	11	11	11	11
EBITDA Build											
Authorized Net Income	97	99	101	103	105	108	110	112	114	117	120
(+) Taxes	38	38	39	40	41	42	43	44	44	45	46
Earnings Before Taxes (EBT)	135	137	140	143	146	150	153	156	159	162	166
(+) Interest	35	36	37	38	39	40	40	41	42	43	44
Earnings Before Interest and Taxes (EBIT)	170	174	177	181	185	189	193	197	201	205	210
(-) Interest	(35)	(36)	(37)	(38)	(39)	(40)	(40)	(41)	(42)	(43)	(44)
Taxable Income	135	137	140	143	146	150	153	156	159	162	166
(-) Federal Taxes	(26)	(26)	(27)	(27)	(28)	(29)	(29)	(30)	(30)	(31)	(32)
(-) State Taxes	(12)	(12)	(12)	(13)	(13)	(13)	(13)	(14)	(14)	(14)	(15)
Authorized Net Income	97	99	101	103	105	108	110	112	114	117	120
(+) Preferred Stock Dividend	1	1	1	1	1	1	1	1	1	1	1
(+) Interest	35	36	37	38	39	40	40	41	42	43	44
(+) Federal Taxes	26	26	27	27	28	29	29	30	30	31	32
(+) State Taxes	12	12	12	13	13	13	13	14	14	14	15
(+) D&A	89	93	98	97	102	107	113	118	124	119	116
EBITDA	259	267	276	279	288	297	307	316	326	325	326

b. Peer Group and Application to the Valuation

Q21. How are comparable companies important to your valuation of the Assets?

A21. Jefferies reviewed and analyzed certain financial information, valuation trading multiples and market trading data related to selected comparable publicly traded regulated utility companies whose operations Jefferies believes, based on its experience with companies in the regulated utility industry and professional judgment, to be generally relevant in analyzing the Assets.

Trading multiples for relevant public companies are used to understand how similar companies are valued on a relative basis based on key financial metrics. Jefferies primarily used two key metrics, the Earnings Multiple and the EBITDA Multiple (both as defined below) for these comparable companies in both the DCF Analysis and the Comparable Trading Multiples Analysis. Additionally, for the Comparable Trading Multiples Analysis we used a multiple reflecting the Aggregate Value to Rate Base (the "Rate Base Multiple"). Their specific application within each valuation is discussed in more detail herein.

Q22. What comparable companies did Jefferies include?

A22. The selected group of companies used in this analysis, which we refer to as the "Peer Group," was as follows:

- NextEra Energy, Inc.
- Duke Energy Corporation
- The Southern Company
- Dominion Energy, Inc.
- American Electric Power Company, Inc.
- Sempra Energy
- Xcel Energy Inc.
- WEC Energy Group, Inc.
- Eversource Energy
- Consolidated Edison, Inc.
- DTE Energy Company
- Edison International
- Pinnacle West Capital Corporation
- PG&E Corporation

Q23. Why did Jefferies select these companies?

A23. Jefferies selected the companies reviewed in this analysis because, among other things, the Peer Group operates businesses similar to the business of the Subject Property. However, no selected company is identical to the Subject Property. Accordingly, Jefferies believes that purely quantitative analyses are not, in isolation, determinative in the context of the valuation and that qualitative judgments concerning differences between the business, financial and operating characteristics and prospects of the Assets and the Peer Group that could affect the public trading values of each company also are relevant.

Q24. Why was PG&E Corporation excluded from the Peer Group for calculating the exit multiples for the TVs within the DCF Analysis and for the Comparable Trading Multiples Analysis?

A24. We calculated the relevant multiples for PG&E Corporation; however, we have excluded PG&E from our Peer Group median multiples used for calculating the exit multiples for the TVs for the DCF Analysis and for the Comparable Trading Multiples Analysis. We excluded PG&E because, as of the valuation date of July 27, 2021, the company was still trading at depressed market levels likely reflective of the wildfire risks and impact of its recent bankruptcy filing.

VII. APPLICATION OF THE METHODOLOGY TO THE SPECIFIC CIRCUMSTANCES IN THIS CASE

a. DCF Analysis

Q25. What is a DCF Analysis?

A25. DCF Analysis is a methodology used to derive a valuation by calculating the present value of the estimated FCFs of a business or asset. Present value refers to the current value of future cash flows and is obtained by discounting those future cash flows by a discount rate that takes into account macroeconomic assumptions and estimates of risk, the opportunity cost of capital, capital structure, income taxes, expected returns and other appropriate factors.

Q26. How did Jefferies perform the DCF Analysis?

A26. Jefferies performed a DCF Analysis of the Subject Property using the results of the Rate Base Model previously described. Jefferies calculated the DCF Analysis values for the Subject Property as the sum of the net present value ("NPV") of each of:

- the estimated FCF that the Subject Property is expected to generate for the Forecast Period; and

- the estimated value of the Subject Property at the end of the Forecast Period, referred to as the Terminal Value (the "TV").

For purposes of the DCF Analysis, Jefferies analyzed FCF on both an unlevered basis ("Unlevered DCF Analysis") and levered basis ("Levered DCF Analysis").

i. Unlevered FCF

Q27. How did you calculate the Unlevered FCF?

A27. Unlevered FCF is the money a business or asset has before paying its financial obligations. To derive the Unlevered FCF:

- EBITDA is the starting point from the Rate Base Model
- Tax D&A is then subtracted to calculate Earnings Before Interest, Taxes (EBIT)
- From EBIT, we subtract State and Federal taxes
- Then we add back Tax D&A (from the 2nd step noted above)
- From there, we subtract CapEx and add the change in NWC
- The resulting number is post-tax Unlevered Post-Tax FCF for that year.

Table **4** sets forth the estimated Unlevered FCF for the Forecast Period, as used by Jefferies for purposes of the Unlevered DCF Analysis.

Table 4: Unlevered Free Cash Flow Waterfall

Cash Flow Waterfall ($mm)	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E
EBITDA	$258.9	$267.5	$275.8	$278.8	$287.9	$297.1	$306.5	$316.0	$325.6	$324.9	$326.4
(-) D&A	(142.3)	(192.4)	(193.2)	(194.3)	(195.6)	(197.2)	(198.9)	(200.9)	(208.6)	(216.8)	(225.3)
EBIT	116.7	75.1	82.6	84.5	92.3	100.0	107.6	115.2	117.0	108.1	101.1
(-) State Cash Taxes	(10.3)	(6.6)	(7.3)	(7.5)	(8.2)	(8.8)	(9.5)	(10.2)	(10.3)	(9.6)	(8.9)
(-) Federal Cash Taxes	(22.3)	(14.4)	(15.8)	(16.2)	(17.7)	(19.1)	(20.6)	(22.0)	(22.4)	(20.7)	(19.4)
(+) D&A	142.3	192.4	193.2	194.3	195.6	197.2	198.9	200.9	208.6	216.8	225.3
(-) Capital Expenditures	(137.0)	(140.9)	(144.8)	(148.9)	(153.1)	(157.4)	(161.8)	(166.4)	(171.1)	(175.9)	(180.8)
(+) Change in NWC	(24.7)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.6)
Unlevered Post-Tax FCF	$64.6	$105.2	$107.6	$105.9	$108.6	$111.3	$114.1	$117.0	$121.3	$118.3	$116.7
Unlevered Post-Tax FCF – Adjusted For Partial Period	$27.6	$105.2	$107.6	$105.9	$108.6	$111.3	$114.1	$117.0	$121.3	$118.3	$116.7

Q28. What discount rates did you apply to the Unlevered FCF and TVs for the Unlevered DCF Analysis?

A28. Jefferies applied discount rates ranging from 6.0% to 7.0%. These discount rates were based on Jefferies' judgment of a representative range of a Hypothetical Buyer's weighted average cost of capital ("WACC").

The WACC is comprised of the Cost of Common Equity ("Ke") and the Cost of Debt ("Kd"). These are both calculated based on the market inputs of the Peer Group as of the valuation date.

Q29. How did you determine the Cost of Common Equity and Cost of Debt?

A29. To calculate the estimated Cost of Common Equity of 9.2%, Jefferies used the Capital Asset Pricing Model ("CAPM"), which uses a comparable company adjusted unlevered median beta[8] (0.69), a risk-free rate (1.8% based on the then-current prevailing yield on the 20-year U.S. Treasury debt), an equity risk premium (7.3%, Duff & Phelps Historical Long-Term Average) and an equity size premium (-0.2%, Duff & Phelps Decile 1). Using the median beta is a

[8] Beta (β) is a measure of the volatility of a publicly-traded company to the market as a whole. Stocks with betas higher than 1.0 can be interpreted as more volatile than the market as a whole.

generally accepted approach given it removes the influence of any major outliers that would influence the mean.

To calculate the estimated Cost of Debt of 2.8%, Jefferies used the median pre-tax cost of debt for the Peer Group and multiplied it by (1-Tax Rate).

Q30. How did you use these estimates to calculate the WACC?

A30. Each rate is then weighted based on the equity and debt percentages of the Peer Group to calculate the WACC. The detail of the WACC calculation is shown below in Table 5.

Table 5: Weighted Average Cost of Capital

WACC

Company Name	Price as of 7/27/2021	Diluted S/O	Total Equity Value	Net Debt	Preferred Stock	Minority Interest	Total Cap.	D/E Ratio	Total Debt / Total Cap.	Asssumed Tax Rate (t)[1]	Adj. Beta[2]	1+(1-t) *(D/E)	Unlevered Beta[3]
NextEra Energy, Inc.	77.86	1,966.6	153,123	52,438	-	8,182	213,743	32.5%	24.5%	28.0%	0.99	1.23	0.80
Duke Energy Corporation	106.36	769.2	81,814	65,250	1,962	1,472	150,498	76.5%	43.4%	28.0%	0.98	1.55	0.63
The Southern Company	64.54	1,060.1	68,416	51,480	-	4,877	124,773	70.2%	41.3%	28.0%	1.11	1.51	0.74
Dominion Energy, Inc.	76.83	806.5	61,965	38,251	2,387	339	102,942	59.1%	37.2%	28.0%	0.88	1.43	0.62
American Electric Power Company, Inc.	89.39	500.3	44,717	36,523	-	251	81,491	81.2%	44.8%	28.0%	1.00	1.58	0.63
Sempra Energy	132.63	302.8	40,159	24,061	1,454	1,609	67,283	55.7%	35.8%	28.0%	1.10	1.40	0.78
Xcel Energy Inc.	69.46	538.2	37,384	23,412	-	-	60,796	62.6%	38.5%	28.0%	0.99	1.45	0.68
WEC Energy Group, Inc.	96.50	316.4	30,533	14,664	-	201	45,397	47.7%	32.3%	28.0%	0.97	1.34	0.72
Eversource Energy	87.60	343.5	30,088	18,351	-	156	48,594	60.7%	37.8%	28.0%	1.06	1.44	0.74
Consolidated Edison, Inc.	75.53	353.1	26,668	24,816	-	249	51,733	92.2%	48.0%	28.0%	0.79	1.66	0.47
DTE Energy Company	118.70	193.8	22,998	19,689	-	161	42,848	85.0%	46.0%	28.0%	1.13	1.61	0.70
Edison International	57.15	379.4	21,685	24,276	1,237	1,901	49,099	97.8%	49.4%	28.0%	1.10	1.70	0.64
PG&E Corporation	8.99	1,985.1	17,846	42,201	-	252	60,299	233.2%	70.0%	28.0%	1.74	2.68	0.65
Pinnacle West Capital Corporation	86.36	112.8	9,737	7,097	-	124	16,959	72.0%	41.9%	28.0%	1.15	1.52	0.76
Mean								80.5%	42.2%	28.0%	1.07	1.58	0.68
Median								71.1%	41.6%	28.0%	1.03	1.51	0.69

Cost of Equity Calculation	
Unlevered Beta[4]	0.69
Relevered Beta (beta)[5]	1.05
Risk-Free Rate (Rf)[6]	1.8%
Equity Risk Premium (Rm - Rf)[7]	7.3%
Equity Size Premium (Re)[8]	(0.2%)
Cost of Common Equity (Ke)[9]	**9.2%**

Cost of Debt Calculation	
Pre-Tax Cost of Debt (pKd)[10]	3.9%
Tax Rate (t)	28.0%
Cost of Debt (Kd) = pKd*(1-t)	**2.8%**

Weighted Cost of Capital	Equity	Debt
Weight (We, Wd)	58.4%	41.6%
Cost of Capital (Ke, Kd)	9.2%	2.8%
Contribution to WACC	5.4%	1.2%
WACC		6.5%

Sources: Company Filings, Capital IQ, Bloomberg.
Note: As of July 27, 2021.
(1) Combined federal corporate tax rate and average state tax rate.
(2) Bloomberg 2-Year Weekly Adjusted Beta Reverted to SPX Mean.
(3) Unlevered Beta = Levered Beta / (1+(1-t)*(D/E)).
(4) Represents median unlevered beta.
(5) Beta relevered using 58% equity / 42% debt capital structure.
(6) Bloomberg 20-Year Treasury Spot Yield.
(7) Based on Duff & Phelps Cost of Capital Navigator – Historical Long-Term Average with July 27, 2021 valuation date.
(8) Based on Duff & Phelps Cost of Capital Navigator – Decile 1 with July 27, 2021 valuation date.
(9) Cost of Common Equity = Rf + beta * [(Rm - Rf) + Re].
(10) Median interest expense / total long-term debt.

ii. Levered FCF

Q31. How did you calculate the Levered FCF?

A31. Levered FCF is the money a business or asset has after paying its financial obligations. To derive the Levered FCF:

- EBITDA is the starting point from the Rate Base Model
- Tax D&A is then subtracted to calculate Earnings Before Interest, Taxes (EBIT).
- From EBIT we subtracted Interest Expense to calculate Earnings Before Taxes (EBT)
- We then subtract State and Federal taxes
- Tax D&A (from the 2nd step note above) is added back
- From there, we subtract CapEx and add the change in NWC
- Lastly, we add any debt issuances or subtract any debt repayments
- The resulting number is the post-tax Levered FCF for that year.

Table 6 sets forth the estimated Levered FCF for the Forecast Period, as used by Jefferies for purposes of the Levered DCF Analysis.

Table 6: Levered Cash Flow Waterfall

Cash Flow Waterfall ($mm)	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E
EBITDA	$258.9	$267.5	$275.8	$278.8	$287.9	$297.1	$306.5	$316.0	$325.6	$324.9	$326.4
(-) D&A	(142.3)	(192.4)	(193.2)	(194.3)	(195.6)	(197.2)	(198.9)	(200.9)	(208.6)	(216.8)	(225.3)
EBIT	116.7	75.1	82.6	84.5	92.3	100.0	107.6	115.2	117.0	108.1	101.1
(-) Interest Expense	(35.3)	(36.4)	(37.1)	(37.9)	(38.8)	(39.6)	(40.4)	(41.3)	(42.1)	(43.0)	(43.9)
EBT	81.4	38.7	45.5	46.6	53.5	60.4	67.2	73.9	74.9	65.1	57.2
(-) State Cash Taxes	(7.2)	(3.4)	(4.0)	(4.1)	(4.7)	(5.3)	(5.9)	(6.5)	(6.6)	(5.8)	(5.1)
(-) Federal Cash Taxes	(15.6)	(7.4)	(8.7)	(8.9)	(10.2)	(11.6)	(12.9)	(14.1)	(14.3)	(12.5)	(10.9)
(+) D&A	142.3	192.4	193.2	194.3	195.6	197.2	198.9	200.9	208.6	216.8	225.3
(-) Capital Expenditures	(137.0)	(140.9)	(144.8)	(148.9)	(153.1)	(157.4)	(161.8)	(166.4)	(171.1)	(175.9)	(180.8)
(+) Change in NWC	(24.7)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.6)
(+/-) Debt Issuance (Repayment)	35.7	17.7	17.8	19.9	20.0	20.1	20.1	20.1	19.4	22.3	24.7
Levered Post-Tax FCF	$74.9	$96.7	$98.6	$98.5	$100.7	$102.9	$105.1	$107.4	$110.4	$109.7	$109.8
Levered Post-Tax FCF – Adjusted For Partial Period	$32.0	$96.7	$98.6	$98.5	$100.7	$102.9	$105.1	$107.4	$110.4	$109.7	$109.8

Q32. <u>What discount rates did you apply to the Levered FCF and TVs for the Levered DCF Analysis</u>?

A32. Jefferies applied discount rates ranging from 8.7% to 9.7%. These discount rates, based on Jefferies' judgment, were 50 basis points above and below the estimated Hypothetical Buyer's Ke, as previously described, of 9.2%.

iii. Terminal Values for the Unlevered DCF Analysis and Levered DCF Analysis

Q33. How did you calculate the Terminal Values in the DCF Analysis?

A33. For purposes of the DCF Analysis, Jefferies calculated TV using two separate methodologies: the P/E Multiple ("Earnings Multiple"), and the AV/EBITDA Multiple ("EBITDA Multiple"). Each methodology was then separately applied to the Unlevered DCF and the Levered DCF.

Q34. Please describe the Earnings Multiple methodology to determine TVs.

A34. The Earnings Multiple is an exit multiple approach to calculating TV at the end of the projection period by using historical median Earnings Multiples on comparable companies. The Earnings Multiple is calculated by dividing the current stock price by the Earnings Per Share ("EPS") of these comparable companies. The exit Earnings Multiples used for the DCF analysis were calculated based on the Peer Group.

Q35. Please describe the EBITDA Multiple methodology to determine TVs.

A35. The EBITDA Multiple is an alternative exit multiple approach to calculating TV at the end of the projected period by using historical average EBITDA multiples on comparable companies. The EBITDA Multiple is calculated by taking Aggregate Value (Market Capitalization plus Total Net Debt plus Preferred Equity plus Minority Interest ("AV")), divided by EBITDA. The exit EBITDA Multiples used for the DCF Analysis were based on the Peer Group.

Q36. How did Jefferies apply the results of these TV methodologies?

A36. Jefferies selected a range of Earnings Multiples from 15.8x to 17.8x (1.0x above and below our calculated 16.8x Peer Group multiple median) for the Earnings Multiples TVs, see Figure 1, and a range of EBITDA Multiples from 9.1x to 11.1x (1.0x above and below our calculated 10.1x Peer Group multiple median) for the EBITDA Multiples TVs, see Figure 2. These were both based on the average of the 10-year median historical trading levels for the Peer Group (as shown in the charts below). As of the valuation date , the Peer Group was trading well above 10-year median average on a forward Earnings and forward EBITDA basis. As such, we took a 10-year median average multiple as a more appropriate estimate for determining value in the future.

Figure 1: Peer Group 1-Year Forward Earnings Multiples

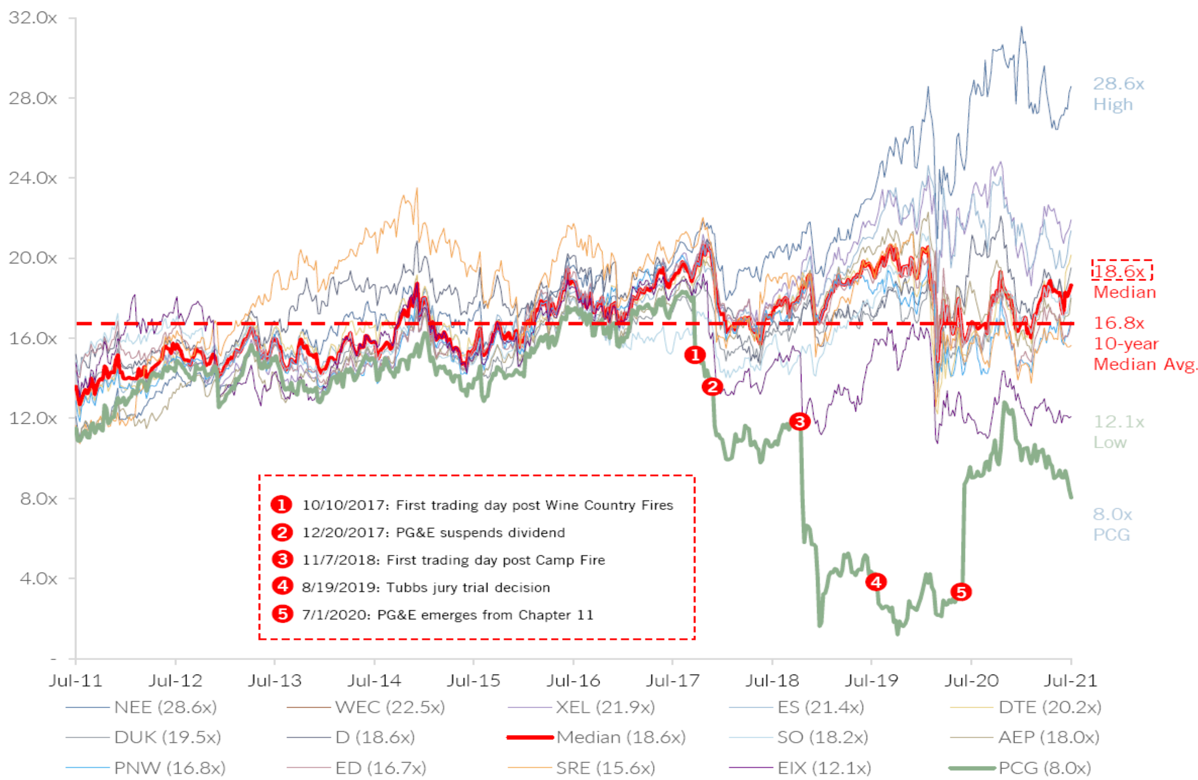
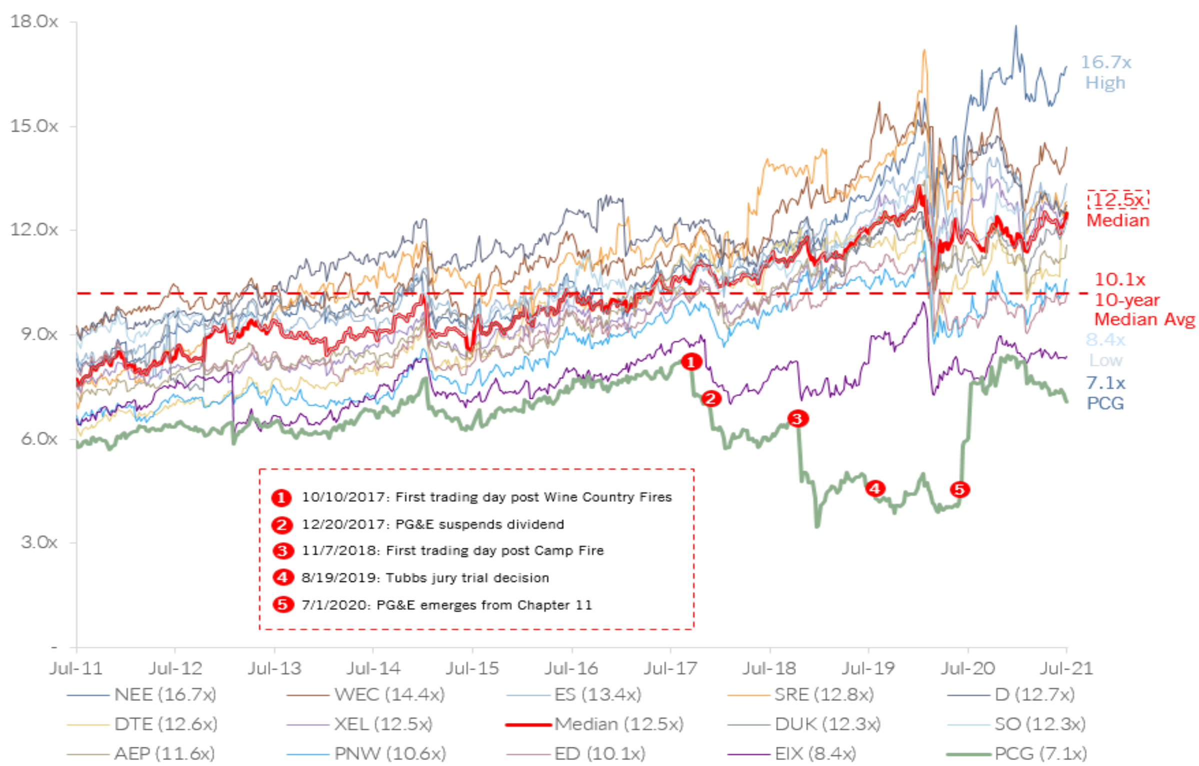


Figure 2: Peer Group 1-Year Forward AV / EBITDA Multiples



Q37. How are the TVs calculated for the Unlevered DCF?

A37. When calculating the TVs for the Unlevered DCF using an Earnings Multiple, the Earnings Multiple is multiplied by the then 1-year forward (i.e., 2032) Authorized Net Income. Then, the then-outstanding (i.e., December 31, 2031) Debt and Preferred Equity balances are added. The sum of those is then discounted back to the valuation date of July 27, 2021 using the WACC.

When calculating the TVs for the Unlevered DCF using an EBITDA Multiple, the EBITDA Multiple is multiplied by the then 1-year forward (i.e., 2032) EBITDA. That value is then discounted back to the valuation date of July 27, 2021 using the WACC.

Q38. How are the TVs calculated for the Levered DCF?

A38. When calculating the TVs for the Levered DCF using an Earnings Multiple, the Earnings Multiple is multiplied by the then 1-year forward (i.e., 2032) Authorized Net Income. That value is then discounted back to the valuation date of July 27, 2021 using the Ke .

When calculating the TVs for the Levered DCF using an EBITDA Multiple, the EBITDA Multiple is multiplied by the then 1-year forward (i.e., 2032) EBITDA. The then-outstanding (i.e., December 31, 2031) Debt and Preferred Equity balances are then subtracted. The resulting value is then discounted back to the valuation date of July 27, 2021 using the Ke .

iv. DCF Analysis Results

Q39. How did Jefferies use these results to develop a DCF range of values of the Assets?

A39. Jefferies took the sum of the NPV based on a range of applicable discount rates of (i) the present value of the Unlevered FCF or Levered FCF for the Forecast Period, and (ii) TVs at the end of the Forecast Period using both the Earnings Multiple and EBITDA Multiple TV methodologies. The range of values as indicated by each DCF Analysis is included in Table 7 below.

Table 7: DCF Analysis Valuation Range

TVs Multiple Methodology	FCF Approach	Implied AV
Earnings	Unlevered	$2.3Bn - $2.7Bn
	Levered	$2.3 Bn - $2.5 B
	Average	**$2.3 Bn - $2.6 Bn**
EBITDA	Unlevered	$2.4Bn - $2.9 Bn
	Levered	$2.3Bn - $2.7 Bn
	Average	**$2.4 Bn - $2.8 Bn**

Note: Average totals may not sum due to rounding.

b. Comparable Trading Multiples Analysis

Q40. What is a comparable company trading multiples analysis?

A40. A comparable company trading multiples analysis is a valuation approach that looks at the current trading multiples for a similar set of publicly traded companies. Those trading multiples are then multiplied by the underlying financial metric of the Assets to calculate an implied value of the Assets.

Q41. What companies did Jefferies use for its Comparable Trading Multiples Analysis?

A41. Jefferies used the Peer Group listed above. That section also provides a description of the basis of their selection.

Q42. What multiples for the Peer Group were used in your Comparable Trading Multiples Analysis?

A42. Jefferies calculated and compared various financial multiples and ratios of each of the Peer Group, including, among other things:

- Earnings Multiple: ratio of each company's July 27, 2021, closing share price to its then-projected calendar year 2022 EPS; and
- EBITDA Multiple: ratio of each company's AV, which Jefferies calculated as the then-current market capitalization of each company (based on each company's closing share price as of July 27, 2021, and fully-diluted share count as of the applicable date specified in its Quarterly Report or Form 10-Q for the quarter ended June 30, 2021), plus debt, plus non-controlling interest, plus preferred stock, less cash & cash equivalents and marketable securities as of June 30, 2021, to its then-projected calendar year 2022 estimated EBITDA;[9] and
- "Rate Base Multiple": ratio of each company's AV, as described above, to its Rate Base as of the valuation date.[10]

[9] The EPS and EBITDA estimates for each of the companies in the Peer Group were based on public filings, Capital IQ consensus estimates, and other publicly available information.

[10] Jefferies sourced the Rate Base data for the Companies in the Peer Group from publicly disclosed investor presentations, earnings reports or filings made by each company.

Q43. What were the results of the Peer Group multiples calculations?

A43. Table 8 summarizes the multiples for the Peer Group.

Table 8: Peer Group Multiples as of 7/27/2021

Utility Comparables

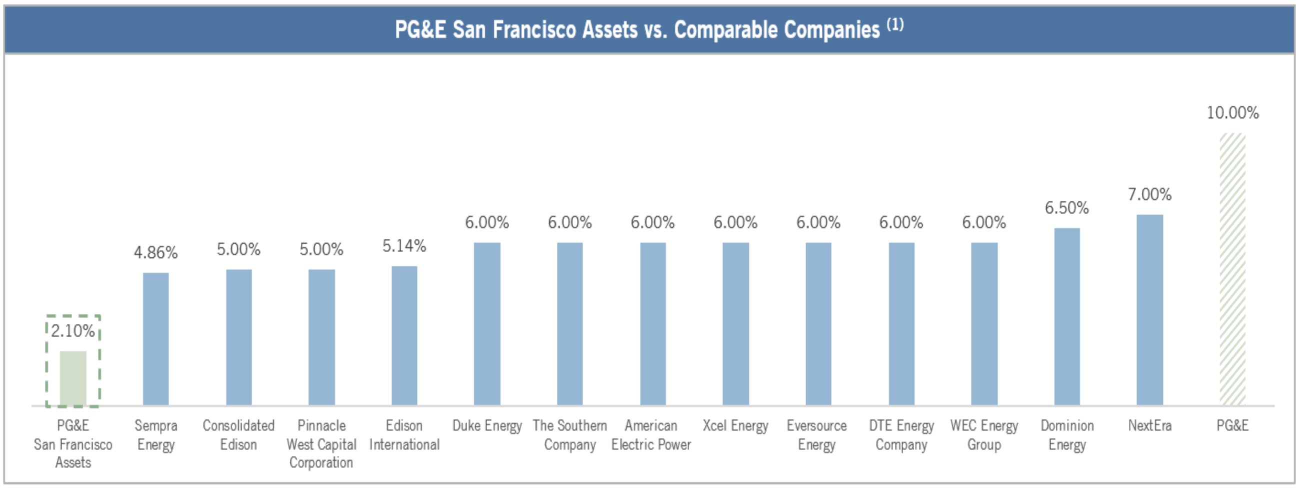
Public Trading Comparables
$mm (unless otherwise noted)

Company	Price as of 7/27/2021	% of 52-Week High	Market Cap	Aggregate Value [1]	P / E FY+1	AV / EBITDA FY+1	AV / Rate Base
NextEra Energy, Inc.	77.86	89%	153,123	213,743	28.6x	16.7x	5.0x
Duke Energy Corporation	106.36	98%	81,814	150,498	19.5x	12.3x	2.5x
The Southern Company	64.54	96%	68,416	124,773	18.2x	12.3x	2.1x
Dominion Energy, Inc.	76.83	88%	61,965	102,942	18.6x	12.7x	2.5x
American Electric Power Company, Inc.	89.39	95%	44,717	81,491	18.0x	11.6x	1.6x
Sempra Energy	132.63	92%	40,159	67,283	15.6x	12.8x	1.8x
Xcel Energy Inc.	69.46	91%	37,384	60,796	21.9x	12.5x	1.7x
WEC Energy Group, Inc.	96.50	90%	30,533	45,397	22.5x	14.4x	2.0x
Eversource Energy	87.60	91%	30,088	48,594	21.4x	13.4x	2.2x
Consolidated Edison, Inc.	75.53	90%	26,668	51,733	16.7x	10.1x	1.6x
DTE Energy Company	118.70	82%	22,998	42,848	20.2x	12.6x	1.8x
Edison International	57.15	86%	21,685	49,099	12.1x	8.4x	1.5x
Pinnacle West Capital Corporation	86.36	94%	9,737	16,959	16.8x	10.6x	1.6x
Mean					**19.2x**	**12.3x**	**2.1x**
Median					**18.6x**	**12.5x**	**1.8x**
PG&E Corporation	8.99	70%	17,846	60,299	8.0x	7.1x	1.4x

Q44. How did you determine the appropriate range of multiples to apply for your Comparable Trading Multiples Analysis?

A44. Based on the Peer Group data, Jefferies performed a benchmarking analysis relative to the projected operating results of the Rate Base Model for the Assets. We looked at the long-term projected Earnings growth rates that each Peer Group company publicly announced on or before the Valuation Date of July 27, 2021. Growth rates are a critical component of valuation for utility companies, and feature prominently in the valuation analysis of equity research analysts. As seen in Figure 3 below, based on the Rate Base Model, the Assets have a lower long-term estimated earnings growth rate relative to the Peer Group. Therefore, based on our professional judgment and expertise, we assumed the Assets would command a multiple (for each of Earnings, EBITDA, and Rate Base) that is no greater than, and likely below, the Median of the Peer Group.

Figure 3: Subject Property vs. Peer Group Projected Earnings Growth



(1) Reflect long-term earnings growth rates that each comparable company publicly stated on or before July 27, 2021 within its earnings presentation, earnings call script, or investor day presentation. Growth rates stated are Compounded Annual Growth Rates ("CAGR").

Therefore, Jefferies selected the following multiples ranges for the Comparable Trading Multiples Analysis:

- 15.6x – 18.6x for the FY+1 Earnings Multiple; and
- 10.5x – 12.5x for the FY+1 EBITDA Multiple; and
- 1.5x – 1.8x for the Rate Base Multiple.

Q45. What valuation is suggested by these results?

A45. The range of values of the Assets, as indicated by each Comparable Trading Multiples Analysis methodology is included in Table 9 below.

Table 9 Comparable Trading Multiples Valuation Range

Multiple	Implied AV
FY+1 Earnings	$2.4 Bn – $2.7 Bn
FY+1 EBITDA	$2.8 Bn – $3.3 Bn
Rate Base	$2.8 Bn – $3.4 Bn
Average	**$2.7 Bn – $3.1 Bn**

Note: Average totals may not sum due to rounding

c. Precedents Analysis

Q46. How did Jefferies perform its Precedents Analysis?

A46. Jefferies reviewed and analyzed selected precedent M&A transactions involving companies in the electric utility industry it viewed as generally relevant in analyzing the Assets. In performing this analysis, Jefferies reviewed certain financial information and transaction multiples relating to the companies involved in such selected announced transactions prior to the valuation date as of July 27, 2021, and compared such information to the corresponding information for the Assets. Specifically, Jefferies selected and reviewed 14 M&A transactions announced since June 2014 involving companies in the electric utility industry for which sufficient public information was available (the "Precedent Transactions") : see Figure 4 and Figure 5.

Figure 4: Precedent Transactions AV / EBITDA and AV / Rate Base Multiples

Figure 5: Precedent Transactions P / E Multiples

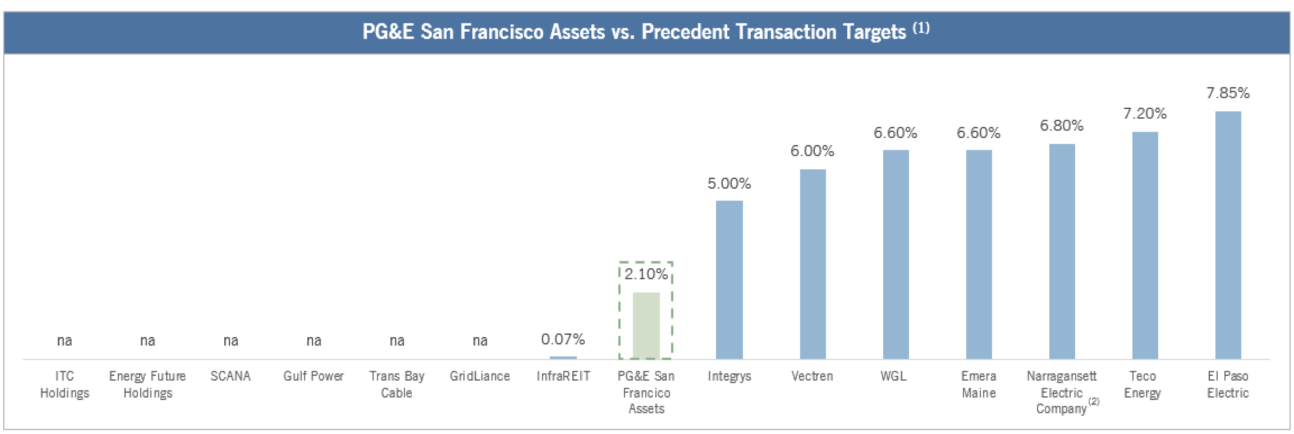
Q47. How did you determine the appropriate range of multiples to use for your Precedents Analysis?

A47. Jefferies performed a benchmarking analysis of the Assets relative to the Precedent Transactions. We looked at the long-term estimated Earnings growth rates that each Target (of each Precedent Transaction) publicly announced on or before the respective transaction announcement date. As previously stated, growth rates are a critical component of valuation for utility companies, and feature prominently in the valuation analysis of equity research analysts.

Q48. What were the results of this analysis?

A48. As seen in Figure 6, based on the Rate Base Model, the Assets have a much lower long-term estimated Earnings growth rate than most of the Targets of the Precedent Transactions. Therefore, based on our professional judgment and expertise, we assumed the Assets would likely command a multiple (for Earnings, EBITDA, and Rate Base) that is no greater than, and likely lower than, the Median for the Precedent Transactions.

Figure 6: Subject Property vs. Precedent Transaction Targets



(1) Reflect long-term earnings growth rates for the Target company of each Precedent transaction publicly states on or before the transaction announcement within its investor presentation, transaction announcement, or equity research report. Growth rates stated as CAGRs.
(2) Represents targeted Rate Base growth, instead of earnings growth.

To the extent publicly available, Jefferies reviewed, among other things, the Earnings Multiple, the EBITDA Multiple, and the Rate Base Multiple of each of the Targets implied by the Precedent Transactions. Based on an analysis of these multiples, as well as its professional judgment and experience, Jefferies selected the following multiples ranges to be applied to the Precedents Analysis:

- 20.0x – 23.0x for the FY+1 Earnings Multiple; and
- 10.2x – 12.2x for the FY+1 EBITDA Multiple; and
- 1.6x – 2.1x for the Rate Base Multiple.

Q49. What valuation is suggested by these results?

A49. The range of values of the Assets, as indicated by each Precedents Analysis methodology, is included in Table 10 below.

Table 10: Precedent Transaction Valuation Range

Multiple	Implied AV
FY+1 Earnings	\$2.9Bn - \$3.2Bn
FY+1 EBITDA	\$2.7Bn - \$3.3Bn
Rate Base	\$2.9Bn - \$3.8Bn
Average	**\$2.8Bn - \$3.4Bn**

Note: Average totals may not sum due to rounding.

d. ***Hypothetical Market Value***

Q50. How would you weight the relative importance of each valuation methodology in determining a range of Hypothetical Market Values?

A50. All the previously discussed valuation methodologies would factor into a Hypothetical Buyer's view of value. However, a Hypothetical Buyer would not likely place equal weight on each of them, given the unique characteristics and circumstances of the Subject Property. The DCF Analysis looks at the intrinsic value of these Assets and the cash flows they would generate, whereas the Comparable Trading Multiples Analysis and Precedents Analysis do not account for these unique characteristics and circumstances. Based on its professional judgment and expertise, Jefferies weighted the results of each of these methodologies based on how it believes a Hypothetical Buyer would view the relative significance of each.

Jefferies used weightings of:

- 40% for the DCF with Earnings Multiple on the average range of $2.3Bn - $2.6Bn; and
- 10% for the DCF with EBITDA Multiple on the average range of $2.4Bn - $2.8Bn; and
- 25% for the Comparable Trading Multiples Analysis on the average range of $2.7Bn - $3.1Bn; and
- 25% to Precedents Analysis on the average range of $2.8Bn - $3.4Bn.

Q51. What is your conclusion regarding what a Hypothetical Buyer would be willing to pay for the Subject Property?

A51. This analysis resulted in a Hypothetical Market Value range for the Subject Property of $2.5 to $3.0 billion, as set forth below in Table 11.

Table 11: Weighted Average Hypothetical Market Value

Methodology	Weighting	AV Range
DCF with Earnings Multiple	40%	$0.9Bn - $1.0Bn
DCF with EBITDA Multiple	10%	$0.2Bn - $0.3Bn
Comparable Trading Multiples Analysis	25%	$0.7Bn - $0.8Bn
Precedents Analysis	25%	$0.7Bn - $0.9Bn
Weighted Average (Hypothetical Market Value)		**$2.5Bn - $3.0Bn**

Note: Weighted Average may not sum due to rounding.

Figure 7 shows the implied AVs for each valuation methodology that we analyzed as well as the weighted average range indicating the Hypothetical Market Value range for the Subject Property.

Figure 7: Range of Valuation Methodologies

Equity / 2022E Earnings	($99mm) (5)	11.3x	16.4x	21.4x	26.5x	31.5x
AV / 2022E EBITDA	($267mm)	7.5x	9.3x	11.2x	13.1x	15.0x
AV / 2021E Rate Base	($1,819mm)	1.1x	1.4x	1.6x	1.9x	2.2x

Sources: Capital IQ, Press Releases, Investor Presentations, Wall Street Research, NewGen – "Appraisal of PG&E Electrical Distribution and Transmission Facilities in the City of San Francisco".
Note: As of July 27, 2021.
(1) Based on average of the 10-year median historical trading levels for the comparable companies.
(2) 6.0%-7.0% WACC assumed based on current adjusted beta for comparable companies.
(3) 8.7%-9.7% cost of equity assumed based on current adjusted beta for comparable companies.
(4) Utilizes average min and max value of each valuation methodology. Calculated as 40% DCF w/ Earnings Multiple + 10% DCF w/ EBITDA Multiple + 25% Comparable Companies + 25% Precedent Transactions.
(5) Based on $882mm forecast debt balance as of December 31, 2022.

Q52. Does that conclude your testimony?

A52. Yes.

Table 12: Glossary

Term	Abbreviation (if applicable)	Definition
% of 52-Week High		Represents the current share price as a percentage of the highest share price over the preceding 52-week period. Ranges from 0% to 100%.
Accumulated Deferred Income Tax	ADIT	IRS rules allow companies to take advantage of accelerated depreciation, which lowers income tax payable during the earlier years of an asset's life, whereas FERC's ratemaking policies use straight-line depreciation. The difference between actual tax owed and tax liability for ratemaking purposes is reflected in an ADIT account and is subject to specific procedures under IRS rules. Because ADIT balances are effectively cost-free capital, they are also subtracted from a utility's Rate Base during ratemaking
Aggregate Value	AV	The entire value of the business that equals Market Capitalization plus Net Debt plus Preferred Equity plus Minority Interest. AV = Market Cap + Net Debt + Preferred Stock + Minority Interest
Authorized Net Income		The authorized Return on Equity based on the regulated utility's equity base of the Rate Base. Authorized Net Income = Rate Base * Authorized Equity Capitalization * Authorized ROE
Capital Asset Pricing Model	CAPM	Describes the relationship between systematic risk, or the general perils of investing, and expected return for assets, particularly stocks. It is a finance model that establishes a linear relationship between the required return on an investment and risk. The model is based on the relationship between an asset's beta, the risk-free rate (typically the Treasury bill rate), and the equity risk premium, or the expected return on the market minus the risk-free rate
Capital Expenditures	CapEx	Funds used by a company to acquire, upgrade, and maintain physical assets such as property, plants, buildings, technology, or equipment. Capital Expenditures is a component of rate and consequently an increase in Capital Expenditures constitutes an increase in Rate Base.
Comparable Companies Trading Multiples Analysis	Comparable Trading Multiples Analysis	A valuation process used to determine the value of a company using metrics of similar companies in terms of size and industry. The process takes the average of a selected Multiple (EV / EBITDA, Price / Earnings, etc.) and applies the selected Multiple against the target company or assets.
Cost of Debt	Kd	The annual interest rate that a company pays on its debts, such as bonds and loans
Cost of Common Equity	Ke	Represents the compensation that the market demands in exchange for owning the asset and bearing the risk of ownership. The traditional formula for the Cost of Common Equity is the Capital Asset Pricing Model

Deferred Tax Assets	DTA	An asset created due to the fact that the target's assets are depreciated on a GAAP book basis but not for tax purposes. A Deferred Tax Asset is created when taxes are paid or carried forward but cannot yet be recognized on the company's income statement. The Deferred Tax Asset line item on the balance sheet remedies this accounting difference between book basis and tax basis.
Deferred Tax Liabilities	DTL	A liability is created due to the fact that the target's assets are depreciated on a GAAP book basis but not for tax purposes. The Deferred Tax Liability represents a future tax payment that the company is obliged to pay. The Deferred Tax Liability line item on the balance sheet remedies this accounting difference between book basis and tax basis.
Depreciation and Amortization	D&A	Non-cash expenses that flow through the three main financial statements. Depreciation is the expensing of a fixed asset as it is used to reflect its anticipated deterioration. Amortization is the practice of spreading an intangible asset's cost over that asset's useful life.
Discounted Cash Flow Analysis	DCF	A valuation methodology that estimates the value of an investment based upon the present value of its expected cash flows. Using a predetermined discount rate that is for the most part derived using a Weighted Average Cost of Capital formula, one discounts the Free Cash Flow to the valuation date.
Earnings Before Interest, Taxes, Depreciation, and Amortization	EBITDA	An alternate measure of profitability to Net Income that is not influenced by financing decisions and taxes. EBITDA = Net Income + Interest + Taxes + Depreciation Expense + Amortization Expense
Earnings Before Interest and Taxes	EBIT	Calculated as revenue minus expenses including Depreciation and Amortization but before considering Tax and Interest. EBIT = EBITDA - Depreciation Expense - Amortization Expense
Earnings Before Taxes	EBT	Calculation of a firm's earnings before taxes are deducted. It is calculated by subtracting all expenses besides taxes from revenue. EBT = EBITDA - Depreciation Expense - Amortization Expense – Interest Expense
Earnings Multiple		The value a company's net income divided by the value of its equity. This can be on a per share basis or in total.
Earnings Per Share	EPS	The value a company's Net Income divided by either its shares outstanding or its fully diluted shares outstanding.
EBITDA Multiple		The value a company's EBITDA relative to its Aggregate Value. This metric is useful for considering a company’s earnings before accounting for its financing decisions.
Free Cash Flow	FCF	The cash that a company generates after accounting for cash outflows to support operations and maintain its capital assets.

Hypothetical Market Value		Fair Market Value of the hypothetically liquidated assets.
Levered FCF		Represents the amount of cash available to a company after considering the cost debt. Calculated as earnings before taxes times 1-Tax Rate plus Depreciation and Amortization minus the change in net working capital minus Capital Expenditures. Levered Free Cash Flow = (EBT * (1-Tax Rate)) + D&A – change in NWC - CapEx
Market Capitalization	Market Cap	The value represented by a given company' s fully diluted shares outstanding multiplied by its share price.
Modified Accelerated Cost Recovery System	MARCS	A depreciation system used for tax purposes in the U.S. MACRS depreciation allows the capitalized cost of an asset to be recovered over a specified period via annual deductions.
Net Debt		The value of a company's debt outstanding less cash on hand. Can be a positive or negative number depending on if the company's cash position exceeds its debt outstanding.
Net Present Value	NPV	The difference between the present value of cash inflows and the present value of cash outflows over a period of time.
Net Utility Plant		The amount constituting the total utility plant of the assets/utility, less depreciation, computed in accordance with RUS accounting requirements.
Net Working Capital	NWC	The difference between a company's current assets—such as cash, accounts receivable/customers' unpaid bills, and inventories of raw materials and finished goods—and its current liabilities, such as accounts payable and debts.
NewGen Appraisal Report		"Appraisal of PG&E Electrical Distribution and Transmission Facilities in the City of San Francisco" by NewGen Strategies and Solutions, LLC on April 10, 2023.
Original Cost Less Depreciation	OCLD	Actual price paid for an asset at acquired minus accumulated depreciation.
Precedent Transaction Analysis	Precedents	A valuation method in which the price paid for similar companies in the past is considered an indicator of a company's value.
Preferred Stock	Pref	A class of stock that is granted certain rights that differ from common stock, generally higher priority of claims and a higher positing in a cash distribution waterfall than common equity.

Rate Base		The asset base, net of accumulated depreciation from which the utility provides electric service and upon which the utility is allowed to earn a rate of return.
Rate Base Multiple		A company's Aggregate Value divided by its Rate Base. This metric is useful for considering a company's value relative to the size of its Rate Base.
Replacement Costs		The amount of money a business must currently spend to replace an essential asset like a real estate property, an investment security, a lien, or another item, with one of the same or higher value.
Return on Equity	ROE	Equal to Net Income over shareholders' equity.
Subject Property		Electrical distribution and transmission facilities and related real property assets located within the City boundaries, and portions of the Martin Substation located in San Mateo County, California, that are presently owned and operated by Pacific Gas & Electric Company (PG&E).
Taxes Other Than Income Taxes	TOTIT	Includes Taxes such as Sales Tax, Gross Receipts Tax, and Taxes on Property.
Terminal Value	TV	The value of an asset, business, or project beyond the forecasted period when future cash flows are estimated.
Unlevered Free Cash Flow		Represents the amount of cash available to a company before considering the cost and composition of its capital base. Calculated as Earnings before Interest times 1-Tax Rate plus Depreciation and Amortization minus the change in net working capital minus Capital Expenditures. Unlevered Free Cash Flow = (EBIT * (1-Tax Rate)) + D&A – change in NWC - CapEx
Weighted Average Cost of Capital	WACC	Represents a firm's average after-tax cost of capital from all sources, including Common Stock, Preferred Stock, Bonds, and other forms of Debt. WACC is the average rate that a company expects to pay to finance its assets. WACC = ((Market value of Equity / Market Value of the Firm) * Cost of Equity) + ((Market Value of Debt / Market Value of the Firm) * Cost of Debt * (1 - Tax Rate))