TURN DATA REQUEST-012
SDG&E-SOCALGAS 2019 GRC – A.17-11-007/8
SDG&E_SOCALGAS RESPONSE
DATE RECEIVED: FEBRUARY 7, 2018
DATE RESPONDED: MARCH 6, 2018

Exhibit Reference: SDG&E-14
Witnesses: Colton
Subject: Electric Dist. Capital

1. Regarding SDG&E's response to DR TURN-SEU-003, question 6 Excel attachment:
    a. Please provide all amounts shown in this Table in nominal dollars and constant 2016 dollars and include all calculations and escalation/de-escalation factors. Please provide in Excel with working formulas.

    b. Please explain what "PTY" projects are (footnote 1).

    c. Please explain why there are no approved amounts for the years 2009 and 2013.

Utility Response 01:

a. See the accompanying Excel document, "TURN-SEU-DR-012 Q1a."

b. Post-test year (PTY) projects are forecasted projects that have capital expenses during the forecast period, but the in-service date is anticipated after the test-year. As a result, these projects are not included in the test-year ratebase, they are shown in order to be included in overhead calculations within the revenue requirements model.

c. 2009 and 2013 do not have explicitly approved capital expense amounts because these years are attrition years for the prior respective GRCs, and SDG&E does not forecast capital expenses in the attrition years. For example, the 2008 GRC revenue requirement is derived from capital expenses forecasted for the 2006-2008 timeframe. 2009 was the first attrition year and did not have authorized capital expenses. Similarly, in the following 2012 GRC, 2013 was the first attrition year where the revenue requirement was derived from forecasted capital expenses for the 2010-2012 timeframe. The attrition years are trued up in the following rate cases, where the actual recorded costs are included in the base year rate base calculations. 2009 was the base year for the TY 2012 GRC and 2013 was the base year for the TY 2016 GRC.

2. Regarding transformers, pages 261 and 262 of the workpapers:

   a. Please provide the basis, quantitative support, and an accompanying explanation of how SDG&E's costs are forecast for 2017-2019. This should include, at a minimum, all escalation factors used and an explanation for expected unit cost increases if applicable.
   b. Please explain how (and if) average historical costs for this category inform the forecasted costs.

   c. Please provide the table on WP page 261 that shows historical and forecasted costs in Excel.

   d. Re WP 261: Are the historical costs for transformers "purchased" or "installed" in that year?
      i. If the numbers are different, please provide the number of transformers "purchased," and the number "installed" in each year 2012-2016, segregating by major type of transformer.

   e. Please provide the historical (2012-16) number of and forecast (2017-2019) number of line transformers associated with the cost data in WP 261. If historical data includes different models with different unit costs, please provide the number and cost for relevant models for each year.

   f. Re WP 262:
      i. Please quantify the increased unit cost of using FR3 fluid versus mineral oil.
      ii. When did SDG&E start using FR3 fluid? Please identify the year and month.
      iii. Please identify the number of units installed using FR3 fluid versus mineral oil in each year recorded 2012-2016 and forecast 2017-2019.

Utility Response 02:

   a. The forecast methodology is based on historical usage data from 2016, which includes projected new business usage increase and projected manufacturer price increases/decreases which is contractual index pricing, subject to change on a quarterly basis based on the metals market fluctuation.

Utility Response 02:-Continued

b. Historical costs have no influence on these forecasted costs. SDG&E has contractual index pricing, which is subject to change on a quarterly basis based on the metals market fluctuation. Forecasted costs are developed using current costs and metals market projection.

c. The table shown on workpaper page 261 does not originate or exist as a spreadsheet, therefore SDG&E cannot provide it.

d. The historical costs for transformers represent purchased transformers for the applicable year.

   i. Below contains the number of transformers installed.

Year	Amount
2012	4640
2013	4321
2014	4090
2015	4858
2016	5140

Below is the number of transformers purchased.

Year	Qty Purchased
2012	6,189
2013	4,846
2014	4,873
2015	9,426
2016	4,722

e. See number of transformers purchased table under question d.i for years 2012-2016. Please see the accompanying file "TURN-DR-012-SDGE Historical Transformers.xlsx" containing quantity per model and associated cost.

f. Re WP 262:

   i. The price increase for FR3 varied by transformer type and manufacturer, and was approximately a 10% average increase.

Utility Response 02:-Continued

ii. SDG&E started ordering FR3 fluid in transformers beginning in last quarter of 2015.

iii. SDG&E did not track past installations of transformers with FR3 fluid. These type of transformers began installation within SDG&E service territory in 2016, along with existing inventory of transformers with mineral oil.

3. Page AFC-115 of testimony describes pole replacements for a "large scale communications infrastructure provider" (budget code 15257). In the Excel spreadsheets provided in TURN-SEU-003 ("ED Capital Expenses) this is referred to as the "Google Fiber" project:

    a. Please confirm that these costs are related to the Google Fiber project, or how this is related.

    b. Please explain why Google is not responsible for some or all of the costs for these pole replacements.

    c. Please provide all evidence of why these costs are necessary, including documents that show what poles will be overloaded and what telecommunication equipment will be deployed.

    d. Why have there been no historical costs for this cost category? If there have been any historical costs, please identify the amounts, the budget codes where they are recorded, and the workpapers where they are presented.

    e. Please explain why costs are expected to begin in 2018 for this budget category, and provide all supporting documents/evidence/links.

Utility Response 03:

a. Public Utilities Code sections (Pub. Util. Code §§) 701, 767, and 1702 authorize the California Public Utilities Commission (Commission) to regulate public utilities and to establish reasonable rates, terms, and conditions for joint use of utility poles, ducts, conduits, and ROW (together, "utility ROW"). In Decision (D.) 98-10-058, the Commission adopted rules to provide facilities-based telecommunication firms with nondiscriminatory access to utility ROW. As such, the costs within this budget are related to all telecommunication companies that will have a large-scale infrastructure deployment project. That would include, but not be limited to, Google Fiber.

b. These costs apply when SDG&E is responsible for a pole replacement that was determined through a large-scale deployment project, in accordance with Commission precedent. During a project, if it has been determined that a pole has a pre-existing condition that requires a change-out and SDG&E was responsible for the pre-existing condition, then the total pole costs are the responsibility of SDG&E and not the company conducting the large-scale deployment.

Utility Response 03:-Continued

c. Through the course of normal business procedures, the company that is responsible for the pre-existing condition has always been responsible for the total cost of replacing the pole, in accordance with Commission precedent. Currently the specific poles have not yet been identified for replacement. Due to the large number of poles being considered for these infrastructure deployment projects, historical experience indicates it reasonable to anticipate that SDG&E will be responsible for a number of poles to be changed out.

d. Previously, communication companies have never engaged in these type of large-scale deployment projects so there are no historical costs or data to draw from. Historically, pole change-outs have been determined through other courses of utility business functions and not to this mass scale. The high volume nature of these deployments represents an upward spike in the corporate maintenance budgeting.

e. SDG&E objects to this request as overly broad, unduly burdensome and not reasonably tailored to lead to admissible evidence. Subject to and without waiving this objection, SDG&E states as follows: SDG&E is currently in discussions with communication companies regarding large-scale deployment projects that are expected to begin in 2018. At the current time, SDGE has not executed any related agreements or contracts.

4. Regarding the Local Engineering Pool and SDG&E's response to TURN-SEU-003, question 18:

   a. With regard to page 394 of the workpapers, please confirm that the costs shown in step "1b" have already been excluded from step "1a." If not, why were these costs not subtracted from step "1a" to form the basis of SDG&E's forecast?

   b. Please explain whether step "1a" includes all capital costs that inform the basis of this overhead pool.

   c. If not described above, please explain how step "1b" informs the forecasted overhead budget, if at all.

   d. Budget code 8165 of the "OH Pools" spreadsheet shows costs of about $1.8 million in 2016, while this same budget code shows 2016 costs of $7.2 million in the "ED Capital costs" spreadsheet. Please reconcile this discrepancy, including any differences in the data sets, and provide revised spreadsheets if there are errors.

   e. Regarding the Table shown in step "1a" on page 394 of the workpapers, please provide this Table in Excel and include historical (recorded) capital costs on an annual basis from 2012-2015 relevant to this Local Engineering Pool. Please include all supporting workpapers/calculations, including at a minimum a list of the budget codes that form the basis of this Pool.

Utility Response 04:

a. SDG&E confirms that the costs shown in step "1B" have been excluded from step "1a".
b. Step "1a" includes all capital costs that inform the basis of the overhead pool.
c. Step "1b" is the step to exclude costs that are not applicable to the OH Pools calculation base.
d. As shown on page 912 of the workpapers, adjustments were made to the historical costs that were inadvertently excluded in the original accounting history extract. The correct ED capital costs for budget code 8165 for 2016 is $7.2 million. The Local Engineering Pool was calculated using the first round extract.
e. SDG&E used 2016 as the base year to forecast the Local Engineering Pool. Because SDG&E used 2016 as a base year, SDG&E does not have the same table with costs on an annual basis from 2012-2015. Please refer to TURN_DR-03 Q18 – OH Pools Supporting Tables.xlsx, provided in response to TURN 03.

5. Regarding page 404 of the workpapers, step "1a," please provide this Table in Excel and include historical (recorded) capital costs on an annual basis from 2012-2015 relevant to the basis of this Local Engineering Pool - Substation. Please include all supporting workpapers/calculations, including at a minimum a list of the budget codes that form the basis of this Pool.

Utility Response 05:

Because SDG&E used 2016 as base year to forecast the Local Engineering Pool – Substation, SDG&E does not have the same table with costs on an annual basis from 2012-2015. Please refer to TURN_DR-03 Q18 – OH Pools Supporting Tables.xlsx, provided in response to TURN 03.

6. Regarding page 414 of the workpapers, step "1a," please provide this Table in Excel and include historical (recorded) capital costs on an annual basis from 2012-2015 relevant to the basis of this Department Overhead Pool. Please include all supporting workpapers/calculations, including at a minimum a list of the budget codes that form the basis of this Pool.

Utility Response 06:

Because SDG&E used 2016 as base year to forecast the Department Overhead Pool, SDG&E does not have the same table with costs on an annual basis from 2012-2015. Please refer to TURN_DR-03 Q18 – OH Pools Supporting Tables.xlsx, provided in response to TURN 03.

7. Regarding page 422 of the workpapers, step "1a," please provide this Table in Excel and include historical (recorded) capital costs on an annual basis from 2012-2015 relevant to the basis of this Contract Administrator Pool. Please include all supporting workpapers/calculations, including at a minimum a list of the budget codes that form the basis of this Pool.

Utility Response 07:

Because SDG&E used 2016 as base year to forecast the Contract Administrator Pool, SDG&E does not have the same table with costs on an annual basis from 2012-2015. Please refer to TURN_DR-03 Q18 – OH Pools Supporting Tables.xlsx, provided in response to TURN 03.

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8. Regarding SDG&E's response to TURN-SEU-003, question 27:

  a. Please provide the values in the chart from SDG&E's response to question 27c in Excel. Please also provide these values in constant 2016 dollars and include all calculations and escalation factors in Excel.
  b. Please provide the calculation of historical growth in this account that demonstrates the 3% growth expected.

Utility Response 08:

  a. Please see the accompanying Excel document "TURN-DR-012-TURN Data Request Question 8a." for reference.

  b. There were three calculations performed for the 236 budget to find the most logical expectation of growth. The first was the unweighted average, which is the change in actual dollar spend year over year from 2001 through 2016. Average Annual Growth Rate (AAGR) 17.2%. The second calculation was performed using the AAGR within one standard deviation equating to 9.1%. The final calculation is simply the average US inflation rate from 2001 – 2016 at 2.1%. Given the inconsistent historical spend and general nature of this reactive budget a conservative approach was taken as we continue to use the nominal 3% that SDG&E has used historically when forecasting this budget.

9. Regarding SDG&E's response to TURN-SEU-003, question 29(g) attachment:
   a. Please confirm that the Excel file provides 2016 and 2017 *peak* load for the listed circuits.
   b. Please provide peak load data at all 4kV *substations* in Excel in the same format as provided in this response.

Utility Response 09:

a. The excel file provides the peak load for the applicable circuits that would be used by SDG&E for peak analysis.
b. Please refer to the table below:

Substation	2. 2016 (kW)	2. 2017 (kW)
BA	2728.8	2779.7
CV	885.3	1008.5
ESCO	2512.1	2826.9
HP	2021.4	1931.1
NC	838	797.9
SC	2593.8	2545.2
SF	1521.4	1605.9
SHC	1159.5	1125.5
SSC	928.5	954

10. Regarding SDG&E's attachment to TURN-SEU-003, question 37(h), "Transformer and Breaker Age":

    a. Please provide an additional column in the "circuit breaker" tab that indicates whether the circuit breaker is "air," "gas," "oil," or "vacuum."

    b. Please also provide an explanation of the difference between these breaker technologies.

Utility Response 10:

a. See the accompanying file "TURN-DR-012-Transformer and Breaker Age v2"

b. Breaker technologies differ in the insulating medium used to extinguish the arc when the breaker contacts open.
    i. Air breakers use air
    ii. Oil breakers use oil
    iii. Vacuum breakers have the contacts contained inside a vacuum

    In the column labeled "Type", the breaker types are listed as airbreakermetalclad, oilbreaker, vacbreaker, and vacbreakermetalclad. The first part of the type (air, oil, vac) are the insulating medium (air, oil, vacuum). The metalclad suffix refers to breakers that are in a metalclad enclosure.

11. Regarding the "Replace Obsolete Substation Equipment Project" (budget code 992820):

    a. Please provide annual historical unit replacement costs from 2012-2016 for transformers and circuit breakers separately in nominal and constant 2016 dollars. Please provide this in Excel with supporting workpapers.
    b. SDG&E states on page 664 of the workpapers that "The estimated cost of replacing 3% or 9 bank transformers and 5% or 75 distribution circuit breakers is $26M." Please disaggregate this $26 million between bank transformers and distribution circuit breakers, and indicate the unit cost of each assumed. Please provide in Excel with supporting workpapers.

Utility Response 11:

a. The costs associated with the unit replacement has been constant from 2012-2016, it has been the ancillary costs such as pad extensions/replacements, below grade construction, telecommunications and associated substation upgrades that vary from year to year and are project specific. See the accompanying Excel spreadsheet, "TURN-DR-012-11" for the individual unit replacement costs of both transformers and circuit breakers in nominal dollars.
b. See accompanying Excel spreadsheet, "TURN-DR-012-Q11".

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12. Regarding SF6 Switch Replacement and page 711 of the workpapers, SDG&E states "In an effort to reduce greenhouse gas emissions to 1990 levels, with a deadline to achieve by 2020, federal (EPA) & state (CARB) agencies have created respective regulations for utilities to adhere to. The SF6 emission rates are becoming more restrictive each year; 2018 = 3%, 2019 = 2%, and finally 2020 and beyond will be 1%."

   a. Please explain what these percentage emission rates indicate, including but not limited to a formula for how they are calculated.

   b. Please provide documentation or links to the rules from EPA and CARB that show the emission regulation rates indicated in this statement.

   c. Please provide historical (2012-2016) and forecast (2017-2022) SF6 emission rates on SDG&E's system that correspond to the above definition of emission rate. Please provide all assumptions, supporting workpapers, and calculations in Excel.

   d. Please provide SF6 emission rates if no switches are replaced from 2017-2022.

Utility Response 12:

   a. SDG&E objects to this request to the extent that it calls for a legal conclusion and seeks information that is not relevant to the issues before the Commission in this proceeding and that is publicly and equally available to TURN. Subject to and without waiving these objections, SDG&E responds as follows: The following information is available on the EPA website (at https://www.ecfr.gov/cgi-bin/text-idx?SID=2c250337b5491a5d86e98cf5323286df&mc=true&node=sp40.23.98.dd&rgn=div6):

§98.303 Calculating GHG emissions.

(a) Calculate the annual SF_6 and PFC emissions using the mass-balance approach in Equation DD-1 of this section:

User Emissions = (Decrease in SF_6 Inventory) + (Acquisitions of SF_6) − (Disbursements of SF_6) − (Net Increase in Total Nameplate Capacity of Equipment Operated)

(Eq. DD-1)

Utility Response 12:-Continued

where:

Decrease in SF_6 Inventory = (pounds of SF_6 stored in containers, but not in energized equipment, at the beginning of the year) – (pounds of SF_6 stored in containers, but not in energized equipment, at the end of the year).

Acquisitions of SF_6 = (pounds of SF_6 purchased from chemical producers or distributors in bulk) + (pounds of SF_6 purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear) + (pounds of SF_6 returned to facility after off-site recycling).

Disbursements of SF_6 = (pounds of SF_6 in bulk and contained in equipment that is sold to other entities) + (pounds of SF_6 returned to suppliers) + (pounds of SF_6 sent off site for recycling) + (pounds of SF_6 sent off-site for destruction).

Net Increase in Total Nameplate Capacity of Equipment Operated = (The Nameplate Capacity of new equipment in pounds, including hermetically sealed-pressure switchgear) – (Nameplate Capacity of retiring equipment in pounds, including hermetically sealed-pressure switchgear). (Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage).

The following information is available on the ARB website (at https://www.arb.ca.gov/cc/sf6elec/finalregulation.pdf):

(e) *Annual SF_6 Emission Rate.* GIS owners shall use the following equations to determine their SF_6 emission rate.

Equation for determining emissions rate:

$$ER = \frac{Emissions}{C_{avg}}$$

Where:
ER = Emission Rate
Emissions = Annual emissions per subsection (d) (lbs)
C_{avg} = Average system nameplate capacity as expressed in the equation below (lbs)

$$C_{avg} = \frac{\sum_{i=1}^{n}(d_i C_i)}{365}$$

Where:
C_{avg} = The average system nameplate capacity (lbs)
n = The number of GIS devices
d_i = The number of days during the year the GIS device was in active service
C_i = The nameplate capacity (lbs) of the GIS device

b. Links supporting this information are provided below:
- https://www.ecfr.gov/cgi-bin/text-idx?SID=2c250337b5491a5d86e98cf5323286df&mc=true&node=sp40.23.98.dd&rgn=div6
- https://www.arb.ca.gov/cc/sf6elec/finalregulation.pdf

Utility Response 12:-Continued

c. SDG&E objects to this request to the extent that it calls for speculation and seeks information that is not relevant to the issues before the Commission in this proceeding. Subject to and without waiving these objections, SDG&E responds as follows: See table below:

Year[1]	Distribution Emissions		SDG&E Emissions[2]	
	EPA[3]	CARB	EPA	CARB
2012	600.2lbs	4.2%	1905.5lbs	2.1%
2013	353.2lbs	2.5%	524.5lbs	0.47%
2014	461.7lbs	3.4%	1466lbs	1.2%
2015	373.3lbs	2.8%	1509.5lbs	1.15%
2016	267.6lbs	2.2%	528.9lbs	0.4%
2017	~350lbs	~2%	>1000lbs	~1%
2018	~350lbs	~2%	>1000lbs	~1%
2019	~350lbs	~2%	>1000lbs	~1%
2020	~350lbs	~2%	>1000lbs	~1%
2021	~350lbs	~2%	>1000lbs	~1%
2022	~350lbs	~2%	>1000lbs	~1%

d. SDG&E objects to this request to the extent that it calls for speculation and seeks information that is not relevant to the issues before the Commission in this proceeding. Subject to and without waiving these objections, SDG&E responds as follows: If no switches are replaced from 2017-2022, theoretically, the emissions rate for distribution switches could be as low as 0%. This is because of how the above equations are designed; we account for the emissions the year the switch is degassed after its removed from service.

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[1] Forecasting emissions and emissions rate are not part of SDG&E's typical business practice. These forecasts are based on historical information.
[2] Emissions submitted to EPA and CARB include both distribution and substation equipment.
[3] There is a slight difference between how EPA and CARB calculate emissions.

13. Regarding SF6 switch replacement (budget code 14249):

a. Please explain why is there no spending in this budget category from 2012-2015.

b. Have SF6 switches been replaced historically as part of the Switch replacement program (Budget code 289)? If yes, please provide (in Excel):

   i. The number of SF6 switches replaced annually 2012-2016;
   ii. The cost of SF6 switch replacement annually 2012-2016.

c. What is the expected useful life of an SF6 switch? Please provide supporting documentation and/or data.

d. Please explain what the spending in this budget category represents in 2016 (e.g. replacement for failure, due to environmental concerns, etc.).

e. Is it possible to detect if an operational SF6 switch is leaking gas? Please explain.

f. Please provide a list of SF6 switches in SDG&E's territory (in Excel, with appropriate ID or naming convention), when the switch was installed, the location (circuit name and ID), whether padmounted or subsurface, and the expected leakage rate (%) of each switch. Please provide a definition of all terms and supporting workpapers.

g. Please provide the percentage of total GHG emissions in SDG&E's territory due to SF6 switches on a CO2 equivalent (CO2e) basis.

h. Please provide the unit cost to replace or remove an SF6 switch and all supporting workpapers. Please explain (and quantify if applicable) whether there are material differences in unit replacement costs for padmounted versus underground switches.

i. Please provide the TY cost estimate to comply with the CARB regulations cited on page 711 of the workpapers.

j. Regarding SDG&E's response to TURN-SEU-003, question 38(a), please provide the "historical analysis" and any workpapers/sources related to the amount of gas that leaks from SF6 switches on an annual basis.

Utility Response 13:

a. The budget for SF6 switch replacement (budget code 14249) was requested as part of SDG&E's 2016 GRC request, with spending intended to begin in 2016. 2016 and the beginning of 2017 were used to assess the switches in SDG&E's system, and since that time SDG&E has been ramping up its replacement activity.

b. These switches are often found with low gas pressure, and therefore are labeled "Do not Operate Energized" (DOE). DOE switches are replaced as part of the Budget Code 289 which has been in effect for many years.

(i)

Year	Switches
2012	51
2013	33
2014	34
2015	24
2016	26

(ii)

Year	Approx. Cost of SF6 Switch Replacements
2012	$5,865,000
2013	$3,795,000
2014	$3,910,000
2015	$2,760,000
2016	$2,860,000

c. SDG&E objects to this request as vague and ambiguous with respect to the meaning of "expected useful life." Subject to and without waiving this objection, SDG&E responds as follows: Electric distribution switches, whether they are SF6 or non-SF6, are capitalized in Federal Energy Regulatory Commission (FERC) Account E362.10 – Station Equipment. Per Exhibit SDG&E-34-R (Revised Direct Testimony of Matthew Vanderbilt) at MCV-21, the proposed average service life for assets in FERC Account E362.10 is 53 ½ years. Please refer to Exhibit SDG&E-34-R at MCV-21 for more information.

d. The primary spending in this budget category would be for the replacement of DOE (Do Not Operate While Energized) switches, due to low gas levels.

e. A leak can be detected using a specialized gas detection 'sniffing' tool.

Utility Response 13:-Continued

f. Regarding "the location (circuit name and ID)", it is SDG&E's policy not to divulge address information due to sensitive and confidential nature, this includes circuit names and ID's. SDG&E does not make assumptions with the expected leakage rate for each switch.

Approximate SF6 Switch Counts by Year:

Year	Padmount	Subsurface	Vault	Total
1980		1		1
1982	1		1	2
1983	2			2
1985	1			1
1986	2	1		3
1987	5			5
1988	57	12	2	71
1989	74	19	4	97
1990	34	1		35
1991	49	7		56
1992	87	6		93
1993	73	5	1	79
1994	46	8	1	55
1995	59	8		67
1996	29	6		35
1997	8	4		12
1998	22	9		31
1999	6	2	2	10
2000	9	15	6	30
2001	13	15	16	44
2002	13	5	5	23
2003	8	22	7	37
2004	9	5	2	16
2005	3	2	4	9
2006	5	14	6	25
2007	1	12	8	21
2008			3	3
2009	1	11	4	16
2010		2		2
2011	2	1		3
2012	2	6		8
2013	1	11	1	13
2014	1	5		6
2015		5		5
2016	1	1		2
2017	2			2
Total	**626**	**221**	**73**	**920**

Utility Response 13:-Continued

g. The percentage of total GHG emissions in SDG&E's territory due to SF6 switches on a CO2 equivalent (CO2e) basis is approximately 0.53% (SF6 is 5,773 CO2e of 1,098,348 CO2e)

h. Approximate Costs:
   - Pad-mounted Range: $35k - $114k
   - Pad-mounted Average: $95,070
   - Submersible Range: $26k - $147k
   - Submersible Average: $97,125

i. The test year estimate needed to comply with the CARB regulations is approximately $14,088,000.

j. See the accompanying files
"TURN-DR-012-Historical SF6 Evaluation Record 2010.pdf"
"TURN-DR-012-Historical SF6 Evaluation Record 2011.pdf"
"TURN-DR-012-Historical SF6 Evaluation Record 2012.pdf"
"TURN-DR-012-Historical SF6 Evaluation Record 2013.pdf"
"TURN-DR-012-Historical SF6 Evaluation Record 2014.pdf"
"TURN-DR-012-Historical SF6 Evaluation Record 2015.pdf" and
"TURN-DR-012-Historical SF6 Evaluation Record 2016.pdf"

14. Regarding page 489 of the workpapers (4kV substations, budget code 6260):

a. SDG&E states "Certain equipment inside the substations such as transformers and breakers are obsolete, and replacement parts no longer available." Please provide a list of replacement parts that are no longer available for purchase in 4kV substations, and an explanation for why the part is no longer available.

b. Related to part (a), please explain the impact of lack of replacement parts. Does SDG&E need to replace an asset with a different model or type, or does the entire substation need to be replaced if replacement parts are unavailable?

c. Are models of all assets used in a 4 KV substation (for example: transformers, circuit breakers, switch racks, voltage regulators, capacitors, etc.) available on the market, even if the models or types of assets may be different from the ones presently installed on SDG&E's 4 kV substations?
   i. If not, please identify what assets cannot be purchased presently from vendors?
   ii. If yes, can those assets be used to replace existing assets? If not, why not?

d. Please provide an explanation for why there are no historical costs for this category.

e. SDG&E states "the maintenance cost [on 4kV stations] is unusually high and continues to increase." Please provide annual historical 4kV maintenance costs from 2012-2016 on 4kV substations versus 12kV substations in Excel.

f. Please provide the number of customers served by each 4kV substation in Excel.

Utility Response 14:

a. SDG&E objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it is burdensome, overbroad, and not reasonably tailored to lead to the discovery of admissible evidence. Subject to and without waiving this objection, SDG&E responds as follows: In general, equipment installed within our 4kV substations such as electromechanical relays, older packaged subs / metalclad switchgear, oil/air circuit breakers, and transformers are obsolete and/or 'one-off' designs that do not meet SDG&E's current standard with regard to substation design.

Utility Response 14:-Continued

It is because of this that it becomes difficult, case by case, to obtain replacement parts to continually address the aging state of these substations in order to ensure safe and reliable service to our customers. SDG&E does not have a comprehensive list of the individual parts and pieces related to the equipment we are proposing to replace in whole.

b. The 4 kV Modernization program does not necessarily aim to replace 4 kV substations. Rather, the program seeks to upgrade 4 kV distribution infrastructure to 12 kV based on expected future reliability and reduced maintenance requirements. Construction typically will target conversions from the tail end of 4 kV circuits, thus leaving 4 kV substation elimination as one of the final activities for each project. In lieu of implementing this program, replacement substation parts may become critically scarce, carrying risks to electric operations because they are not readily available in SDG&E's inventory. For example, if a package 4 kV substation unit were to fail catastrophically, SDG&E would need to install a temporary substation as a custom part was ordered and delivered several months following the event. These activities could cause unnecessary disruptions to service and put SDG&E's limited portable 4 kV substation availability at risk for other operational issues that may arise.

c.
   i. As mentioned in part b, the lack of readily available parts/equipment for legacy 4kV equipment contributes to significant reliability concerns if said legacy equipment were to fail. The proactive replacement of 4kV infrastructure aims to preempt failures of said obsolete legacy infrastructure while at the same time bringing these substations and circuits up to current SDG&E standards.
   ii. Some modern 4 kV assets in substations can be replaced in-kind or with functionally equivalent alternatives; however, even if these assets are available today and in the near future, their limited availability and eventual obsolesence may cause logistical issues when the time comes that they need to be replaced, such that a comprehensive strategy is warranted to prevent reliability impacts.

d. 4 kV conversion activities were not commonly budgeted separately in the 6260 budget code. Earlier 4 kV conversion activities were often recorded to other primary budget codes, such as overhead-to-underground conversions or other 12 kV reliability enhancements collocated with 4 kV facilities. Historically, a 4 kV substation may not have been eliminated if doing so would not directly benefit the intended 12 kV project.

Utility Response 14:-Continued

e. See the accompanying Excel document, "TURN-DR-012-Sub Maintenance Cost Comparison," showing average costs in nominal dollars. Since SDG&E maintains substation equipment on a time based schedule, the range of years from 2012 to 2016 won't necessarily demonstrate the trend of increasing maintenance costs on 4kV equipment, but still shows the average cost of maintaining 4kV assets is higher than the 12kV assets.

f. See the accompanying Excel document, "TURN-DR-012-Number of Customers Served by 4KV Subs.xls".

15. Regarding the Cleveland National Forest Power Line Replacement Projects (budget code 8165), please provide the number of residents (SDG&E customers and, if known, total population) in the area where fire risk is expected to be mitigated due to this project.

Utility Response 15:

It is estimated that 750,000 residents would benefit directly and indirectly from the CNF project.

16. Re. Budget code 10265 (Avian Protection) and SDG&E-14-CWP p. 210:

a. Please provide an annual breakdown of 2012-2016 costs for this budget category into inspections, retro-fits, replacements, and any other more activity applicable to this budget code.

b. Please provide the percentage of poles that have been inspected through 2016 that lie in the Avian Protection Zone.

c. Please provide the date when the three identified federal and state laws and regulations went into effect.

d. Have these laws and regulations been in existence with substantially the same provisions since 2012? If not, please identify the date of any significant changes.

e. What are the APLIC Guidelines? When were they issued?

f. When was the "Avian Protection Zone" established? Does it change annually?

g. Please provide the total number of OH distribution poles within the Avian Protection Zone in each year 2012-2016 recorded and 2017-2019 forecast.

h. Please provide the number of OH distribution poles replaced within the Avian Protection Zone in each year 2012-2016 recorded and 2017-2019 forecast

i. Please provide the number of "known bird contacts" each year 2012-2016 in SDG&E's service territory.

j. Please explain the reason for the reduced costs in 2015 and 2016 compared to 2012-2014?

Utility Response 16:

a. SDG&E does not have this breakdown in the categories requested. All the spending is for retrofitting poles with avian equipment.

   For available 2012-2016 Avian Budget cost breakdowns, see the accompanying EXCEL spreadsheet, "TURN-DR-012-Avian Budget Analysis 2012 – 2016"

b. 5.5% of poles that have been inspected through 2016 lie in the Avian Protection Zone.

c. Migratory Bird Treaty Act: enacted in 1918 and subsequently amended.
   Bald and Golden Eagle Protection Act: enacted in 1940 and subsequently amended.
   California State Fish and Game Code: enacted in 1957 and subsequently amended.

d. SDG&E objects to this request to the extent that it calls for a legal conclusion and seeks information that is publicly and equally available to TURN. Subject to and without waiving this objection, SDG&E states as follows: Upon information and belief, SDG&E understands these laws and regulations to have been in existence with substantially the same provisions since 2012.

e. APLIC is the Avian Power Line Interaction Committee, which consists of representatives from the utility industry, federal and state wildlife resource agencies, conservation groups, and avian protection manufacturers. In 2006, APLIC released *Suggested Practices for Avian Protection on Power Lines.* These documents provide the industry and federal and state agency standard for avian protection.

f. The avian protection zone was initially established in 2000. The Avian Priority Areas/Zones will be updated in 2018.

g. There are approximately 40,000 OH distribution poles within the avian protection zone.

h. There is no forecast of poles in the aviation protection zone for future years, as the work performed is based on inspections, which trigger pole replacements.

Utility Response 16:-CONTINUED

Below is the number of poles replaced from 2012 to 2016. Please note budget 10265 only pays for the avian cover ups, and does not pay for pole replacements themselves. Pole replacement costs are largely captured under the 87232 or other budgets (e.g., FiRM, damage caused by vehicle contacts, etc.). As a result, the number of pole replacements has no direct correlation with the Avian Protection budget.

2012	483
2013	520
2014	405
2015	848
2016	1539

i.

	2012	2013	2014	2015	2016
Known bird contacts	98	58	45	79	80

A reassignment of field inspection personnel to higher priority work resulted in fewer construction orders of this type in 2015 and 2016.

17. Re. Budget code 13264 (Distributed Generation Interconnect):

    a. What is the basis for the assumed scope of work in 2017 and 2018?

    b. Re. p. AFC-51, lines 11-12: Please provide a list of all projects in the interconnection queue, with at least the following information in excel format for each project:

        i. Applicable tariff (Rule 21 or WDAT)
        ii. Nameplate capacity
        iii. NEM or wholesale project
        iv. Projected in-service date
        v. Location (circuit ID)
        vi. Forecast interconnection cost

    c. Re. p. AFC-51, lines 15-18 and WP p. 225: showing 2016 historical cost of $253,000. Please provide the number of projects interconnected in 2016 that form the basis for the recorded cost, and for each project, please provide:

        i. Tariff (Rule 21 or WDAT)
        ii. Nameplate capacity
        iii. NEM or wholesale
        iv. Projected in-service date
        v. Forecast interconnection cost
        vi. Actual interconnection cost

Utility Response 17:

a. The basis for the assumed scope of work in 2017 and 2018 is engineering, design and construction of interconnection facilities from generator switchgear to the point of interconnection on SDG&E's distribution system.

b. See the accompanying Excel spreadsheet "TURN-DR-012-Distributed Gen Interconnect_TURN12_17b"

c. See below showing 2016 historical costs. See the accompanying Excel spreadsheet in part b for parts i-vi.

Utility Response 17:-Continued

Budget Code	Cost Element	Work Order	WO Description	2016 Recorded Actual
13264	Labor	2389710	LILAC-A82 SOLAR PROJ W(67)	799
		2389711	LILAC-A82 SOLAR PRJ W(67) G	2,568
		2389712	LILAC-A82 SOLAR PROJ W(6 R1	6,476
		2392720	CREELMAN:RAMONA SOLAR PR R1	4,202
		2392721	CRE:RAMONA SOLAR PROJ W3 R1	2,598
		2392722	CREELMAN:KEARNY SCADA WO R1	6,339
		2969792	C908,VC: KEARNY SCADA WO R1	15,747
			VACATION & SICK	6,000
			TOTAL Labor	**44,729**
13264	Non-Labor	2389710	LILAC-A82 SOLAR PROJ W(67)	40,825
		2389711	LILAC-A82 SOLAR PRJ W(67) G	17,695
		2389712	LILAC-A82 SOLAR PROJ W(6 R1	14,214
		2392720	CREELMAN:RAMONA SOLAR PR R1	36,163
		2392721	CRE:RAMONA SOLAR PROJ W3 R1	12,154
		2392722	CREELMAN:KEARNY SCADA WO R1	326
		2458530	NLP VALLEY CENTER SOLAR C90	9,892
		2969790	C908,VC:SOLAR PROJ (W59) GE	57,897
		2969791	C908,VC:SOLAR PROJ (W59) GE	11,950
		2969792	C908,VC: KEARNY SCADA WO R1	7,503
			TOTAL Non-Labor	**208,618**

18. Regarding budget Code 002020 (meters) and SDG&E's Response to TURN-SEU-003-14:

a. In DR 003-14(a) and (f) the company explains that it capitalizes meters at time of purchase, and describes various cost factors. TURN does not find the text responsive to question (f). Please explain and quantify how the actual numerical forecast for 2017-2019 was calculated based on the "factors" identified in DR 003-14. If the cost was simply a matter of expert judgement, please state so. If specific numerical scope of work forecasts were used, please identify and quantify.

b. Re WP 253 – How does SDG&E determine how many meters and regulators to purchase in a particular year?

c. What is the basis for capitalizing meters at the time of purchase, rather than at the time of installation?

Utility Response 18:

a. SDG&E used expert judgement along with the previous year's average monthly usage to determine the forecast. Further explanation is contained within the response for 18.b.

b. SDG&E uses its new business forecast and historical usage when determining purchases for meters and regulators. SDG&E issues orders based on demand and adjusts them as requirements vary.

c. The basis for capitalizing meters at the time of purchase is associated with the ability to purchase meters in bulk.

19. Re. Budget Code 00230 (cable replacement), has SDG&E instituted a cable testing program for underground cable?
    a. If yes, please provide the miles of cable tested each year 2012-2016?
    b. If no, please explain why not.

Utility Response 19:

19a and 19b: SDG&E has not instituted a cable testing program for underground cable. SDG&E has a comprehensive cable failure database and historical cable purchasing records, which has allowed SDG&E to calculate expected cable failure rates for unjacketed cable and identify poor performing vintages. These failure rates are used in a reliability analysis program to evaluate the cost/benefit of proposed proactive cable replacement jobs to replace unjacketed cable.

TURN DATA REQUEST-012
SDG&E-SOCALGAS 2019 GRC – A.17-11-007/8
SDG&E_SOCALGAS RESPONSE
DATE RECEIVED: FEBRUARY 7, 2018
DATE RESPONDED: MARCH 6, 2018

20. Re Budget Code 11249 (SCADA on Capacitors) :

a. Re. WP 513 – please identify the number of line capacitors converted to SCADA each year 2012-2015.

b. If there was any other work (besides installation of line capacitors) that materially impacted historical costs, please identify and quantify that work for each year.

c. Re WP 514

   i. Is the "specific scope of work" forecast for 2017-2019 mean the number of converted line capacitors?

   ii. If yes, please provide that number for each year 2017-2019.

   iii. If no, please explain what is the scope of work and quantify using appropriate units for each year 2017-2019.

Utility Response 20:

a.

LINE CAPACITORS CONVERTED TO SCADA	
YEAR	COUNT
2012	53
2013	81
2014	11
2015	4

b.

The most significant impact to the historical spend on this budget is the initial purchase of electrical equipment to be installed. SCADA capacitors were purchased in bulk quantities in years 2012 and 2013 for future wide deployment on the system. Because of this, the budget has seen lower spend over subsequent years, attributable to the installation costs.

c.

   i. Yes

Utility Response 20:-Continued

ii.

LINE CAPACITORS TO BE CONVERTED TO SCADA	
YEAR	COUNT
2017	20
2018	150
2019	150

iii. N/A

21. Re Budget Code 112670 (SCADA expansion – automated switches) :

a. Re. WP 543 - Please identify the number of automated switches, and any other assets included in the historical cost data, installed each year 2012-2016.

b. Re. WP 543 - Please identify the number of automated switches forecast for installation each year 2017-2019.

c. Re. WP 544 – Does the "specific scope of work" mean the number of automated switches forecast to be installed? If no, please identify any other assets of work included in the scope of work.

d. Please quantify the reliability benefits on an annual basis from 2012-2016 due to installation of automated switches.

e. Please quantify the safety benefits on an annual basis from 2012-2016 due to installation of automated switches.

Utility Response 21:

a. Budget Code 11267 addressed the installation and/or upgrades of SCADA devices and/or controllers on approximately 18 circuits in 2012, 7 circuits in 2013, and 2 circuits in 2014, 0 circuits in 2015, and 0 circuits in 2016

   Major material charges to Budget Code 11267 include the following:

   - 16 Distribution Line SCADA Devices (9 delivered in 2012, 7 delivered in 2013)
   - 9 Substation Medium Voltage Circuit Breakers (9 delivered in 2012)
   - 7 Substation Relay Control Panels (7 delivered in 2012)

   Note that the year purchased material is invoiced does not necessarily correspond to the year the material is installed nor the year the material is commissioned.

b. This project (Budget Code 11267) addresses approximately 20 Distribution Line SCADA Sites between 2017 and 2019.

Utility Response 21:-Continued

c. Projects under this budget are planned by individual distribution circuit. The "specific scope of work" is referring to the number of automated switches, their configuration and their location on each distribution circuit.

d. SDG&E's reliability programs fall primarily into several categories:

- Expansion of SCADA systems and FLISR implementation
    - o These systems reduce or eliminate impacts of initial restorations to customers
- Proactive Aging infrastructure Replacement Programs
    - o Reduce instances of equipment failure leading to customer outage

Historical reliability information can be found at:

http://www.cpuc.ca.gov/General.aspx?id=4529

In recent years the investments that reduce restoration times designed to improve SDG&E's reliability program have been offset by the implementation of practices designed to reduce SDG&E's wildfire risk. These practices include turning off reclosing on circuits in the fire threat zones (FTZ), and requiring physical patrol before re-energizing circuits to prevent downed wires from igniting dry brush. Evidence of the increased restoration times can be found in SDG&E's annual report in the link above by focusing on CAIDI (average customer restoration times) in the Northeast (NE) and Eastern (EA) districts.

When reviewing these reports, you will also notice a large variation in values from year to year. These variations are local environment-specific and are caused by rainfall, storm/wind events, and load peaks experienced from year to year that both cause outages directly and trigger early equipment failure.

e. SDG&E does not have a safety-specific analysis for this project. However, safety benefits from additional SCADA data will include the implementation of improved protective relay settings to more precise margins, enhancing safety while optimizing reliability by reducing trouble shooting time following a safety or fire-related event.

TURN DATA REQUEST-012
SDG&E-SOCALGAS 2019 GRC – A.17-11-007/8
SDG&E_SOCALGAS RESPONSE
DATE RECEIVED: FEBRUARY 7, 2018
DATE RESPONDED: MARCH 6, 2018

22. Regarding "Advanced Ground Fault Detection" (budget code 122460):

a. Please identify the historical and forecast number of major equipment units (relays; service restorers; etc.) installed in 2012-2016 and forecast for 2017-2019 as part of this work.

b. How does SDG&E determine the scope of work for this project?

c. Please provide any cost-benefit analyses for this project.

d. Could the enhanced ground fault detection schemes be used on other areas instead of other fire risk mitigation measures?

Utility Response 22:

a. 120 controllers are forecasted to be installed between 2017 and 2019. Approximately 40 devices/sites are planned per year. This will be a combination of substation relay upgrades and additional line SCADA controllers as identified. 90 Distribution Line SCADA Controllers were installed from 2012-2016.

b. Substations that reside within SDG&E's High Risk Fire Area (HRFA) and SCADA controllers on distribution feeders that enter the Fire Threat Zone (FTZ) are identified for upgrades.

c. SDG&E does not have a cost-benefit analysis for this project. This project is driven by improving public safety and reduction of fire risk from energized downed conductors.

d. No, the enhanced ground fault detection schemes used cannot be in lieu of other fire risk mitigation measures as the enhanced ground fault detection schemes will not prevent such things as downed wire .