**FIRST DATA REQUEST**

**OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION (SEIA)**

**June 1, 2016**

1. Please provide all discovery requests that SDG&E has received in this proceeding from other parties. SEIA will then indicate which responses it would like to obtain. Alternatively, if SDG&E has established a data repository for data requests & responses for this case, please provide SEIA with information on how to access that data base.
2. Please provide a complete copy of SDG&E’s workpapers for its application and supporting testimony. All formulas in all spreadsheets should be intact, and any spreadsheets should be provided in Excel format rather than as an Adobe Acrobat (i.e. as a “.pdf” format”) file.
3. Please provide a full year, preferably 2014 or 2015, of data on the hourly demands (8,760 hours) at each of SDG&E’s 133 primary and secondary substations for which such data is available (see Baranowski Testimony, at p. JB-2). Generic (e.g. numbered) substation labels may be used if SDG&E prefers, for security reasons or to preserve customer confidentiality. Please identify each substation by overall region (i.e. coastal, inland, mountain, or desert).
4. Please respond to the following questions regarding Schedule DG-R:
   1. Please confirm that SDG&E is not proposing any changes in the Schedule DG-R rate design in this application. (See SDG&E witness Chris Swartz at page CS-41, which says that SDG&E does not propose any changes to the current “structure” of Schedule DG-R.)
   2. Please explain how SDG&E has designed the DG-R rate in this application.
   3. Please explain whether SDG&E’s proposal for a 4 to 9 p.m. weekday on-peak period, as indicated in Table 2 of Cynthia Fang’s direct testimony (pages CF-20 to CF-21), will impact the design of Schedule DG-R. Will the only impacts on DG-R customers as a result of the change in TOU periods be the change in commodity rates applicable to Schedule DG-R?
   4. Would SDG&E continue to recover a portion of distribution costs using an energy rate for Schedule DG-R, rather than through demand charges?
   5. If TOU periods are updated, how would that affect the rate component for distribution costs recovered through an energy rate for Schedule DG-R?
5. Please provide the following information on the number of commercial and industrial (C&I) solar customers that are on Schedule DG-R, and the total installed capacity:
   1. The number of C&I customers that have installed or have pending applications for solar PV systems and that have elected Schedule DG-R rates, since DG-R rates became available in May 2008.
   2. The number of C&I customers that have installed or have pending applications for solar PV systems or other renewable DG systems, and that have qualified for but have not elected DG-R rates, since DG-R rates became available in May 2008. SDG&E can derive this from the total number of C&I customers that have installed or have pending applications for solar PV systems or other renewable DG systems since DG-R rates became available in May 2008, less the number in the response to part (a) of this question.
   3. The total nameplate capacity (in kW or MW) of the solar PV systems installed or applied for by C&I customers who have elected DG-R rates, since DG-R rates became available in May 2008.
   4. The total nameplate capacity (in kW or MW) of the solar PV systems installed or applied for by C&I customers who have qualified for but have not elected the DG-R rate, since the DG-R rate became available in May 2008. SDG&E can derive this number from the total nameplate capacity (in kW or MW) of the solar PV systems installed or applied for by C&I customers since DG-R rates became available in May 2008, less the number provided in response to part (c) of this question.
6. Please explain why SDG&E’s proposed 4 to 9 p.m. on peak period does not encompass the proposed hours of Critical Peak Pricing (CPP) from 2 to 6 p.m. year round? Should not all hours eligible to be CPP hours be on-peak hours, and not semi-peak or off-peak hours? Are not CPP hours, on the top 18 days of the year when capacity is most needed, high cost hours that should be considered on-peak hours?
7. Does SDG&E agree that designing a distribution system using non-coincident peak demand increases the distribution system’s cost, as well as increasing its safety and reliability? (See Baranowski Testimony, at page JB-1).
8. If a substation transformer, distribution transformer, or circuit is designed to meet the peak demand at its specific location (see Baranowski Testimony, at page JB-1), does that mean that it is designed to meet the coincident peak demand of all customers served at that specific location, or does SDG&E design it to meet the sum of the non-coincident peak demands for all of the individual loads served at that specific location regardless of when those noncoincident peak demands may occur?
9. Please discuss the extent to which Mr. Baranowski believes there is load diversity at the following locations on the SDG&E distribution system:
   1. The final line transformer.
   2. The 1,032 SDG&E distribution circuits.
   3. The 133 SDG&E distribution substations.
10. Please provide the data for Figure 1 of John Baranowski’s testimony. Also provide comparable data for SDG&E’s peak days in 2013 and 2015.
11. Please provide the data supporting Figure 2 in the testimony of John Baranowski.
12. Does the substation and circuit load data in Figures 3 and 4 in the testimony of John Baranowski represent (a) the coincident peak demand of all customers served from each substation or circuit or (b) the sum of the non-coincident, individual peak demands for all of the individual loads served from that substation or circuit whenever those noncoincident demands may occur?
13. Regarding the testimony of witness Robert B. Anderson:
    1. Please provide the data supporting Charts RBA-1 to RBA-4.
    2. Please explain if net load in Charts RBA-1 and RBA-2 is based on SDG&E load on the CAISO system, less SDG&E renewables. What types of “distributed generation and central station renewables” were removed to determine net load (i.e. did SDG&E look only at wind and solar on its system that is not behind the meter?). What were the sources of the data used to derive net load?
    3. Please provide the data for the renewable generation removed from SDG&E load data to produce the net loads in Charts RBA-1 and RBA-2.
    4. Please provide any analysis SDG&E has done to show a correlation between net load on its system and the CAISO day-ahead market price at the SDG&E DLAP.
    5. Please provide the 2010-2015 SDG&E DLAP prices used to develop Charts RBA-5 and RBA-6.
    6. Please provide the hourly LOLE data supporting Chart RBA-11, for both the San Diego Subarea and the San Diego Greater Reliability Area.
14. These questions relate to the Testimony of William G. Saxe.
    1. Please provide the workpapers supporting the NERA regressions that resulted in the $77.97 per kW-year marginal distribution costs and $22.05 per kW-year marginal substation costs shown in Attachment A to Mr. Saxe’s testimony.
    2. Please specify and provide the source(s) for the historical and forecast data on annual distribution system peak loads used in these regressions.
    3. How does SDG&E forecast the annual distribution system peak loads used in these regressions?
    4. Do the annual distribution system peak loads used in these regressions measure (a) the coincident peak demand of all customers served from the SDG&E distribution system or (b) the sum of the noncoincident peak demands of all customers served from the SDG&E distribution system, or (c) some other peak demand? If the answer is (c), please explain exactly what peak demand is used.
15. If not already provided, please provide SDG&E’s Marginal Energy Cost (MEC) workpapers, including the 2016 hourly price profile that was based on net demand on the SP-15 market and on-peak / off-peak SP-15 market price projections. (See p. JJS-3 of the Testimony of Jeffrey J. Shaughnessy).
16. Please provide the 2014 and 2015 DLAP prices that support Charts JJS-1 and JJS-2.
17. Please explain why in Table JJS-3 SDG&E assumes that RPS purchases are “incremental” and affect the shape of MECs. Does SDG&E assert that one MW of incremental supply requires, in the short run, a purchase equal to 0.75 MW from SP-15 and 0.25 MW (i.e. a 25% RPS %) of renewable energy? Also, why does not SDG&E shape RPS premiums by TOU period?
18. If not already provided, please provide a copy of SDG&E’s Marginal Generation Capacity Cost (MGCC) workpapers. MGCCs are presented in Section IV of the testimony of William Saxe. Please include the workpapers and calculations of (a) all costs of a new CT that were assumed, (b) the assumed hourly energy market and ancillary service rents that are deducted from CT costs, (c) RECC factors, (d) O&M and other loaders, and (e) escalation to 2016 dollars.
19. Please comment on whether and how the 2011-2014 energy market and ancillary service market earnings in Table JJS-4 for MGCC determination are consistent with SDG&E’s MEC forecast for 2016. What would these earnings become assuming the 2016 forecast, rather than the CAISO’s June 2015 annual report?
20. These questions concern the Ventyx Planning and Risk model discussed in the testimony of witness Robert B. Anderson.
    1. Was 2016 the assumed year for the LOLE determination? If not, what year was assumed, and provide LOLE results for 2016 if available.
    2. Did the Ventyx Planning and Risk model simulate economic dispatch of generation in each hour of 2016?
    3. How did SDG&E/Ventyx model the stochastic output of variable wind & solar renewable resources? Did this modeling assume any correlation between load and renewable output? For example, is there any assumed correlation between solar output and high load days, i.e. does the model consider that it is usually sunny when it is hot in California?
    4. What years were used for the historical data employed in the stochastic process for determining load and renewable production? (See p. RBA-15).
21. Which set of LOLEs were used to form a top 100 hour allocation for MGCC, San Diego Subarea or San Diego Greater Reliability Area, or a combination of the two? (See Chart RBA-11). Also, please describe if possible why the two areas have such different LOLE hourly shapes.
22. Does SDG&E serve all electric loads in the San Diego Subarea? Does SDG&E serve all electric loads in the San Diego Greater Reliability Area? If not, what other utilities serve each of these areas? Please explain the overlap between SDG&E’s certificated electric service territory and these two reliability areas.