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SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

CARL S. LAPETER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

June 1, 2015

#297439

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PREPARED DIRECT TESTIMONY OF

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ON BEHALF OF SDG&E

I. INTRODUCTION

This testimony presents San Diego Gas & Electric Company's ("SDG&E") compliance with the California Public Utility Commission's ("Commission") Good Utility Practice, as discussed below, and reasonable manager standards as defined in Decision ("D.") 02-12-069,[1] with respect to Utility Owned Generation ("UOG") resources planned and unplanned outages during the period of January 1, 2014 through December 31, 2014.

II. COMMISSION STANDARDS RELATED TO SDG&E-OWNED GENERATION

During the record period, SDG&E operated and maintained its UOG resources (Palomar, Desert Star, Miramar, and Cuyamaca; collectively, SDG&E's "UOG units") in a reasonable and prudent manner, consistent with Good Utility Practice and the reasonable manager standard.[2] The Commission defined "Good Utility Practice" in D.02-12-069:[3]

> [A]ny of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not require the optimum

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[1] *See* D.02-12-069, Attachment A-3 at 5.

[2] The Commission has explained the "reasonable manager" standard in certain ERRA compliance cases, as follows: Under the "reasonable manager standard, utilities are held to a standard of reasonableness based on the facts that are known or should have been known at the time. The act of the utility should comport with what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision and act." D.14-05-023 at 15. By meeting the "Good Utility Practice" standard and other Commission requirements stated herein, SDG&E maintains that likewise has met the "reasonable manager" standard during the 2014 record year. The Appendices to this testimony further provide SDG&E's primary showing with respect to both standards.

[3] *See* D.02-12-069, Attachment A-3 at 5.

> practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the Western Electric Coordinating Council region.

Consistent with Good Utility Practice, during 2014, SDG&E followed an established maintenance program to maximize the availability of the units as a primary "desired result." Specifically, this maintenance program factors in a number of considerations, including manufacturer guidelines, appropriate power industry practices, safety considerations, and good engineering and technical judgment to allocate resources most effectively to maximize availability of its UOG resources. Additionally, the SDG&E maintenance program incorporates practices that are generally accepted within the electric power generation industry and the Western Electric Coordinating Council ("WECC").

Additionally, SDG&E is required to comply with the Commission's General Order ("GO") 167 - Enforcement of Maintenance and Operation Standards for Electric Generating Facilities. Sections 10 and 11 of GO 167 specifically outlines each generator owner's obligation to provide information and cooperate with Commission audits, investigations and inspections. Generally, this process may include the following steps:

- In accordance with GO 167 Section 10.1.f, a scheduled, forced or unplanned outage is reported to the Commission representative assigned to the plant, and the Electric Generation Safety and Reliability Section ("EGSRS"), via daily status report email for those days in which the plant is experiencing a forced/unplanned outage. If an outage is reported on the daily status report, a basic description of the outage is also included.
- Once the EGSRS receives the email, a site visit may be scheduled and a data request letter may be sent to SDG&E management.

- During the site visit, the EGSRS typically makes inquires as to the cause of the outage, outage duration, details of repairs required and extent of work to be performed, equipment affected, and evidence of repairs pertaining to the restoration of the unit.
- The EGSRS may issue a data request concerning the outage. The data request typically requires SDG&E to provide control room operator logs, generation curve in megawatts ("MW"), and if available, a root cause investigation or summary of the corrective actions and general photographs that illustrate the outage details.
- After reviewing the response to the data request, the EGSRS may issue additional data requests to obtain more information for review.
- The requests for data continue until the EGSRS closes the inquiry.
- If an outage is extended beyond the scheduled completion date, the EGSRS may contact SDG&E to repeat the process, or part of the process, described above.

In addition to the preceding steps, each outage may warrant the creation of internal documentation, including but not limited to, equipment affected, parts replaced, work required to accomplish outage-related tasks, costs of repairs, other recommended actions that may be taken to mitigate a repeat of the failure, change to operating procedures required to address component or plant issues, changes to maintenance practices to improve reliability, communications with an original equipment manufacturer, and implementation of upgrades to improve reliability. Evidence of the above may be found in parts of the Computerized Maintenance Management System ("CMMS") ordering documents, as well as work orders, vendor invoices, investigation reports, management of change documents, and communications with vendors.

GO 167 also requires SDG&E to meet specific maintenance and operations standards, which also suggest guidance detailed for maintenance and operations programs. These standards and guidance are based on accepted power industry good practices. SDG&E is required to document and certify to these standards every two years, and submit the documentation to the Commission ESRB. The certification documentation includes a summary list of maintenance, operations and safety procedures that describe the programs and processes used in generation.

III. ADDITIONAL REVIEW OF UOG OPERATIONS

Additional review of SDG&E's UOG operations is provided through Sempra Energy Internal Audit Department's audits of SDG&E's generating facilities. Consistent with auditing standards and industry best practices, the frequency and nature of such audits is determined based on the Internal Audit Department's annual risk assessment, which determines the areas of the company, including utility operations, to be audited. This risk-based analysis may change from year to year.

Further, SDG&E's Insurance Risk Consultants conduct site inspections to review and evaluate the plant's physical condition, maintenance, and operations processes. These inspections are performed from a risk perspective and cover maintenance practices, operations practices, material condition, and fire protection. The report may offer recommendations for improvement to systems, facilities, and processes.

SDG&E is also required to meet certain electric reliability standards from the North American Electric Reliability Corporation ("NERC") and WECC. NERC and WECC perform periodic audits of SDG&E to ensure compliance with the reliability standards.

Furthermore, SDG&E generation plants are subject to site visits from various regulators concerning implementation of permits. There are periodic onsite inspections and data requests concerning the implementation of requirements for air permits, water permits, and water discharge permits. SDG&E's Palomar Energy Center is also required to meet permit conditions detailed in the California Energy Commission ("CEC") Operating Permit.

SDG&E's Generation personnel have communicated with the following agencies in 2014:

- California Energy Commission (CEC)
- California Public Utilities Commission (CPUC)
- California Air Resource Board (CARB)
- U.S. Energy Information Administration (US EIA)
- EPA Region 9
- Clark County Department of Air Quality (DAQ)
- Nevada Division of Environmental Protection (NDEP)
- San Diego Air Pollution Control District (APCD)
- Regional Water Quality Control Board (RWQCB)
- CA-EPA State Water Board
- City of Escondido
- Western Electric Coordination Council (WECC)

IV. OUTAGES - UTILITY OWNED GENERATION

Many preventive and corrective maintenance work activities require planned outages, whereas unplanned corrective maintenance is performed under short-notice or forced outages.

Appendix A provides narratives for forced outages 24 hours or longer for all facilities 25 MW or larger. Appendix B provides narratives for planned outages that are 24 hours or longer for all facilities 25 MW or larger, where the outage was extended by two weeks or fifty percent longer, whichever is greater, from its planned schedule. The narratives address, as applicable, the following points:

1. The nature of the outage.
2. The cause(s) of the outage, if known.
3. Possible steps to prevent similar occurrences.
4. Whether the outage may have prevented (or minimized the duration of) a future outage.

V. CONCLUSION

My testimony describes SDG&E's UOG resources located in San Diego County and Nevada. SDG&E consistently followed the Commission's guidance and Good Utility Practice and met the "reasonable manager" standard during the 2014 record year.

This concludes my prepared direct testimony.

VI. QUALIFICATIONS OF CARL S. LAPETER

My name is Carl S. LaPeter. My business address is 2300 Harveson Place, Escondido, CA 92029. I am currently employed by SDG&E as a Plant Manager for Palomar Energy Center, Miramar Energy Facility and Cuyamaca Peak Energy Plant. My responsibilities include overseeing a staff that operates and maintains these power plants.

I began employment at SDG&E in 2005 as Plant Engineer, and then Maintenance Manager, for Palomar Energy Center and Miramar Energy. My experience prior to employment at SDG&E (about 26 years) includes various positions in the US Nuclear Navy, at Palo Verde Nuclear Generating Station and Gila River Power Station.

I hold a Bachelor's of Science degree in Nuclear Engineering Technology from Excelsior College in New York State.

I have not previously testified before the Commission.

APPENDIX A

SDG&E's 2014 UOG Forced Outages Greater Than 24 Hours For Facilities 25 MW or Larger For Units 25 MW or Greater

1. Palomar Energy Center ("PEC") Forced Outage – May 3, 2014 through June 13, 2014 – 42.0 Days

On May 3, 2014, the PEC Steam Turbine Generator ("STG) developed a steam leak on its high pressure turbine case flange. The steam turbine was promptly shutdown, because continued operation with a steam leak of this type is a personnel safety hazard and will also result in increasing damage to the turbine case. In addition, such leaks will get worse as it erodes the case flange.

SDG&E management contacted General Electric ("GE") to schedule an emergency inspection and repair. GE responded quickly and mobilized field engineers and repair crews as well as special tolls that may be needed for the inspection and repair. A repair of this type requires removal of the high pressure turbine case, inspection of the damage, repair of the damage and reinstallation of the case. The case removal and reinstallation require turbine repair crews and field engineers to complete the work. The entire power plant is required to remain shut down for this work to proceed safely.

Prior to the steam leak, this unit was subject to a "scheduled Major Outage." The STG was overhauled, as planned, during the Major Outage. The STG overhaul involved the complete disassembling, inspecting and repairing of identified issues and problems. During the STG Overhaul, GE identified that the high pressure turbine case flange showed signs of the beginning of steam leaks in two areas. There were no indications of these leaks prior to the scheduled Major Outage.

During the scheduled Major Outage, SDG&E and GE field engineers consulted with GE turbine engineers for a repair recommendation. GE engineering provided a repair recommendation to add metal to the flange by welding and then machining the added metal to the correct flatness and dimensions, so that the leak areas would be eliminated when the case was reinstalled. This type of repair is an accepted industry practice for case flange repair. These repairs were completed by the GE field personnel. The STG was started up on with no indication of a steam leak. All of this work was done as part of the scheduled Major Outage.

A few weeks after the scheduled Major Outage completion and STG startup, on May 3, 2014, plant operators identified the steam leak resulting in the shutdown of the STG. After the high pressure steam turbine was cooled, GE field personnel removed the case for inspection. The field personnel identified that the repairs made to the high pressure turbine case flange, during the preceding 2014 scheduled Major Outage of this unit, had failed to prevent the leak formation. GE engineering was again consulted by SDG&E.

GE engineering instructed field personnel to perform extensive dimensional checks and precision measurements to determine why the repair had failed. After reviewing the data, GE engineering determined that insufficient dimensional information was collected before performing the repair during the scheduled Major Outage. GE engineering provided the engineering guidance for the next repair, which changed the final dimensions of the repair. The new repair was completed by GE field personnel and the STG was reassembled and restarted. There were no indications of a steam leak from the case flange after startup, or subsequently.

GE acknowledged that the high pressure steam turbine case flange steam leak was due to their inadequate repair during the 2014 scheduled Major Outage. The steam leak repair was treated as a warranty claim; GE covered the entire cost for the STG high pressure case removal, repair and reinstallation. SDG&E received no charges from GE for this work. GE had repair crews and engineers assigned to work on day shift and night shift and completed this difficult repair in a prompt manner.

Making repair to a high pressure steam turbine case is an involved, time-consuming process and requires many discrete steps and tasks performed in a careful and precise manner. Every aspect of the repair is planned for and performed with precision. Additionally, the time needed for the turbine to cool, the repairs performed, and reassembling the turbine accounts for the duration of the outage.

The next STG overhaul is scheduled for 2022. During this outage, the case again will be removed, inspected, and if necessary, repaired. This inspection and any repair will be done using the previous history of repair as guidance to prevent a similar occurrence.

2. Cuyamaca Peak Energy Plant (CPEP) Forced Outage – May 12, 2014 through May 13, 2014 – 1.1 Days.

On May 12, 2014, the CPEP gas turbine control system initiated a trip to both gas turbines (two turbines power a single generator). The control system indicated that the main fuel gas (natural gas) pressure was too low to properly operate the gas turbines and subsequently tripped the turbines. SDG&E Operations called SDG&E Maintenance to troubleshoot the problem. After investigating the problem and ruling out possibilities, Maintenance determined that the plant systems were not the cause of the low pressure. The main natural gas line pressure to the plant had a transient decrease to a point where the control systems initiated the trip. The transient decrease in the gas line pressure was, in this case, not predictable and short lived. The exact cause of the gas line pressure transient is not known. In SDG&E's four years of operation of CPEP, this main gas line pressure transient has only occurred once.

3. Miramar Energy Facility Unit 1 (MEF 1) Forced Outage – June 4, 2014 through September 29, 2014 – 116.9 Days

On June 4, 2014 the MEF 1 turbine tripped due to an engine stall. A borescope inspection was performed the next day by a General Electric ("GE") field technician. The borescope inspection revealed severe damage to a number of rotating and stationary blades in the high pressure compressor section of the turbine. In addition, at least one rotating compressor blade was missing from its location.

SDG&E evaluated the repairs needed for the turbine. The following were considered in the evaluation: the nature of this repair, other needed repairs planned for the turbine, operating hours on the machine and forecast for operating hours in the future. After this evaluation, SDG&E decided that the best value and most reliability could be achieved through the purchase of a Zero Hours Exchange Turbine. The turbine exchange process requires the trade-in of the customer turbine to be replaced by a rebuilt turbine with the customer paying the exchange price. In this case the exchange turbine was a Zero Hours turbine. This is a turbine that is rebuilt to be treated as new; meaning that the turbine should be treated for maintenance as though it has zero operating hours. In addition, the Zero Hour turbine has all the current engineering reliability and design improvements, eliminating the need to make these improvements to the original turbine.

The purchase of the Zero Hours Turbine was bid to vendors. When the vendor was selected, a contract was issued for purchase and installation. The entire process, from turbine trip through analysis, decision, vendor selection, contract, turbine completion and installation, resulted in the 116.9 day outage.

In discussions with GE, SDG&E found out that the MEF 1 turbine model, a GE LM6000, had also failed at other non-SDG&E locations. Some of the high pressure compressor rotating blades may experience a metal fatigue failure in the retaining foot (dovetail) causing the blade to break free (liberate) and cause extensive damage to the compressor. At the time of this failure, GE had not issued a bulletin to turbine owners to inspect for this problem. The replacement turbine has the same design compressor blades. In subsequent communications with SDG&E, GE recommends periodic inspection of the subject compressor blades. These inspections are based on operating hours and the number of starts. SDG&E will perform these inspections at the prescribed interval. SDG&E is awaiting GE's compressor blade redesign as the final solution; GE is currently testing this new design.

4. Miramar Energy Center Unit 2 (MEF 2) Forced Outage – July 28, 2014 through July 29, 2014 – 1.3 Days

On July 28, 2014, MEF 2, during a turbine startup, experienced a failed Variable Stator Vane (VSV) Sensor, which caused the control system to shut down the turbine. Maintenance performed an inspection and troubleshooting of the VSV system and controls. The troubleshooting indicated a calibration issue. Maintenance attempted to calibrate the system, but was not able to get the calibration to pass. SDG&E Maintenance Management suspected a problem with the turbine controllers, and decided to get assistance with the problem from General Electric, the Original Equipment Manufacturer. The GE technician performed troubleshooting on the control system and determined that the turbine controllers (industrial computers) had configuration errors preventing the calibration. These types of configuration errors are problematic in this controller model and these errors appear occasionally as a result of controller and software design. The technician recommended upgrading to the latest controller to avoid further issues. MEF 2 was already scheduled to have the entire control system replaced a few months later, the control system was replaced by an upgrade from the GE control system to an Emerson Ovation control system, This upgrade is designed to prevent future outages of a similar nature.

5. Desert Star Energy Center (DSEC) Forced Outage – July 2, 2014 through July 4, 2014 – 2.0 Days

On July 2, 2014, the Steam Turbine was forced off line due to failure of the reheat stop valve to open. The reheat stop valve needs to open to supply reheat steam to the steam turbine; without this, the steam turbine could not be started. In order for the reheat stop valve to open the steam turbine intercept valve must be fully closed. Inspection determined that the steam turbine intercept valve was not fully closed, because of an improper mechanical adjustment made during a recent valve overhaul. A valve service vendor performed the mechanical readjustment necessary to restore the valve to operation.

This type of problem will be prevented in the future by ensuring that a full valve stroke test is performed and documented after a valve overhaul. This outage did not prevent or minimize future outages.

6. Desert Star Energy Center (DSEC) Forced Outage – September 9, 2014 through September 11, 2014 – 1.4 Days

On September 9, 2014, Combustion Turbine 1 (CT1) was shut down due to the failure of one of the Beckwith generator protection relays. The Beckwith Relays provides electrical fault protection for the CT1 Generator; CT1 (generator). The CT1 Generator protection system has a partially redundant Beckwith Protection relay installed. Plant management determined that operating the CT1 Generator with the partially redundant system presented risk to the equipment. Management decided to keep the CT1Generator shutdown until the protection relay was replaced, possibly preventing a future more severe outage.

To prevent this type of outage from lasting longer than 24 hours in the future, plant management purchased spare Beckwith Relays for warehouse inventory. In the event of a future protective relay failure, plant personnel will be able to quickly replace the relay, minimizing the plant outage duration.

7. Desert Star Energy Center (DSEC) Forced Outage – October 26, 2014 through October 27, 2014 – 1.1 Days

On October 26, 2014, the plant entered a forced outage due to issues with combustion turbine gas control valve control logic. Troubleshooting found that improper control configuration settings were entered into the fuel gas valve control system by a contracted control system field engineer. The proper control configuration settings were entered into the system, resolving the problem.

Prior to the forced outage, the contracted control system field engineer had installed an upgrade to the combustion turbine generator control system. It was during this upgrade process that the incorrect control configuration settings were entered into the system.

The gas control valve upgrade project provides new features for the calibration and diagnosis of the combustion turbine gas control valves. These improvements provide quicker problem resolution, which will reduce or even eliminate gas control valve outages.

APPENDIX B

Planned Outages 24 Hours or Longer for All Facilities 25 MW or Larger, Extended by Two Weeks or Fifty Percent Longer, Whichever is Greater, From its Planned Schedule

1. No Appendix B Outages are identified for PEC, MEF CPEP or DSEC for 2014.