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Director, Nuclear Regulatory Affairs and
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10 CFR 50.4

January 29, 2013

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Subject: **Docket No. 50-361**
Response to Request for Additional Information (RAI 14)
Regarding Confirmatory Action Letter Response
(TAC No. ME 9727)
San Onofre Nuclear Generating Station, Unit 2

References:

1. Letter from Mr. Elmo E. Collins (USNRC) to Mr. Peter T. Dietrich (SCE), dated March 27, 2012, Confirmatory Action Letter 4-12-001, San Onofre Nuclear Generating Station, Units 2 and 3, Commitments to Address Steam Generator Tube Degradation

2. Letter from Mr. Peter T. Dietrich (SCE) to Mr. Elmo E. Collins (USNRC), dated October 3, 2012, Confirmatory Action Letter – Actions to Address Steam Generator Tube Degradation, San Onofre Nuclear Generating Station, Unit 2

3. Letter from Mr. James R. Hall (USNRC) to Mr. Peter T. Dietrich (SCE), dated December 26, 2012, Request for Additional Information Regarding Response to Confirmatory Action Letter, San Onofre Nuclear Generating Station, Unit 2

Dear Sir or Madam,

On March 27, 2012, the Nuclear Regulatory Commission (NRC) issued a Confirmatory Action Letter (CAL) (Reference 1) to Southern California Edison (SCE) describing actions that the NRC and SCE agreed would be completed to address issues identified in the steam generator tubes of San Onofre Nuclear Generating Station (SONGS) Units 2 and 3. In a letter to the NRC dated October 3, 2012 (Reference 2), SCE reported completion of the Unit 2 CAL actions and included a Return to Service Report (RTSR) that provided details of their completion.

By letter dated December 26, 2012 (Reference 3), the NRC issued Requests for Additional Information (RAIs) regarding the CAL response. Enclosure 1 of this letter provides the response to RAI 14.

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NRR

P.O. Box 128
San Clemente, CA 92672

There are no new regulatory commitments contained in this letter. If you have any questions or require additional information, please call me at (949) 368-6240.

Sincerely,

Enclosures:

1. Response to RAI 14

cc: E. E. Collins, Regional Administrator, NRC Region IV
R. Hall, NRC Project Manager, SONGS Units 2 and 3
G. G. Warnick, NRC Senior Resident Inspector, SONGS Units 2 and 3
R. E. Lantz, Branch Chief, Division of Reactor Projects, NRC Region IV

ENCLOSURE 1

SOUTHERN CALIFORNIA EDISON

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

REGARDING RESPONSE TO CONFIRMATORY ACTION LETTER

DOCKET NO. 50-361

TAC NO. ME 9727

Response to RAI 14

RAI 14

Provide a summary disposition of the U2C17 calculations relative to the planned reduced-power operation.

RESPONSE:

The calculations pertinent to each of the evaluations covered under the responses to RAI 11, 12, and 13 are included in their respective responses. Additional evaluations performed to support the planned reduced-power operation are summarized as follows.

Mechanical Design Evaluations

Assessments of the reactor vessel internals (RVI) analyses, reactor coolant system (RCS) structural analyses, loss of coolant accident (LOCA) hydraulic blowdown loads analyses, and RCS natural circulation analyses of record (AOR) were completed. The assessments addressed the range of power levels from 50% to 100%, and steam generator (SG) tube plugging (SGTP) ratios from 0% to 8%. The results bound and support the planned operation of Unit 2 at 70% power with approximately 3% SGTP.

LOCA blowdown loads, fuel uplift forces, changes in RVI and fuel configuration, and RVI hydraulic loads were addressed to determine the continued validity of the RVI AOR to support the planned Unit 2 operating conditions. The LOCA blowdown loads calculated to support 50% power operation during SONGS Unit 3 Cycle 15 were evaluated and confirmed to bound the planned Unit 2 operating conditions. Fuel uplift force decreases, due to reduction in power and SGTP, are negligible such that the resulting LOCA loads will not be affected and the AOR remains valid for the planned Unit 2 operating conditions. The fuel configuration has been assessed as having no effect on the existing AOR for seismic and LOCA events. Additionally, reduced power operation does not have an effect on the lateral loading on the RVI or fuel and continues to be valid for 70% power. The RVI hydraulic loads are not affected by operation at 70% power. The AOR for RVI remains valid for the planned Unit 2 operating conditions.

For RCS structural analyses, the AOR addresses the faulted load combination consisting of normal operation, safe shutdown earthquake, and pipe break loads. The hydraulic blowdown, cavity pressure, thrust, and jet impingement loads were determined to be bounded by the current design basis analyses. The designs of all RCS components remain bounding for plant operation between 50% and 100% power with up to 8% SGTP.

The LOCA Hydraulic Blowdown Loads Analysis previously performed for the Unit 3 original steam generator (OSG) plant configuration for Cycle 15 operation at 50% power was evaluated for its applicability to the present replacement steam generator (RSG) plant configuration in Unit 2 over the 50% to 100% power range with SGTP ratios up to 8%. The Unit 3 Cycle 15 analysis identified bounding initial values for the critical input parameters for the analysis, including 2300 psia for the maximum RCS pressure (per the U2C17 Reload Ground Rules), 533°F for the minimum RCS cold leg temperature (T_{COLD}), 423,822 gpm for the maximum RCS flow rate, and an RCS hot leg temperature (T_{HOT}) which was computed from the T_{COLD} value and the enthalpy rise at 50% power. The evaluation demonstrated that the planned Unit 2 restart conditions are bounded by the conditions used in the Unit 3 Cycle 15 analysis for 50% power operation and concluded that the analysis results are applicable for the planned Unit 2 operating conditions.

The Reactor System Branch (RSB) 5-1 Natural Circulation analysis AOR was assessed for impacts that would result from plant operation between 50% and 100% power with up to 8% SGTP. The assessment concluded that the changes in the 100% power initial conditions with up to 8% SGTP have an insignificant effect on the condensate water needed for an RSB 5-1 natural circulation cooldown. The condensate requirement at 100% power operation bounds the requirement at lower power levels. The planned reduced power operation with SGTP ratios up to 8% will not affect the plant's ability to establish natural circulation.

I&C Design Evaluations

The Unit 2 instrumentation and control (I&C) systems were assessed for potential impacts from plant operation at 70% power with SGTP ratios up to 8%. The potentially impacted systems included the main steam, main feedwater, and steam generator blowdown flow instruments, the steam generator narrow-range (NR) water level instruments, the plant protection system (PPS) setpoints, the steam bypass control system (SBCS), the digital feedwater control system (DFWCS), and the pressurizer level setpoint and RCS reference temperature (T_{REF}) programs. The results of these assessments are summarized in the following paragraphs.

Whenever the plant operates at reduced power (below 100% power), steam generator saturation pressure and temperature will be higher than the corresponding full-power values. This change in the steam generator conditions affects the process conditions at the sensors of the secondary-side instruments listed above. The transmitter scaling for these secondary-side instruments in Unit 2 was changed for Cycle 17 and is now based on the process conditions that exist at 100% power with a full-power T_{COLD} of 550°F. The indicated value of the measured parameter of each instrument is subject to a process measurement bias error whenever the process conditions at the sensor or transmitter deviate from the base calibration conditions. The consequences of the bias errors that will result from the planned reduced-power operation and increased SGTP during Unit 2 Cycle 17 were found to be acceptable in all cases. No additional transmitter rescaling or instrument recalibration is required.

Main Steam Flow Instruments

Indicated main steam flow at 70% power will be 2.07% less than actual main steam flow because of the higher steam density at the main steam venturis at 70% power compared to the venturi steam density assumed for main steam flow transmitter calibration. Steam pressure at the main steam venturis increases as plant power decreases from 100%. The core operating limit supervisory system (COLSS) main steam flow algorithm does not include dynamic pressure compensation. The algorithm's main steam compressibility factor is fixed and is only accurate at the main steam flow transmitter base calibration conditions (i.e., full-power with T_{COLD} at 550°F). The COLSS main steam secondary calorimetric result (MSBSCAL) will include a bias error that increases as reactor power diverges from 100% power (assuming that calibration to the ultrasonic flow measurement system is unavailable at the reduced power level). The MSBSCAL function is not used by COLSS below 80% power. Main steam flow will not be used for plant power measurement while Unit 2 operates at 70% power. The main steam flow signal is also provided to the DFWCS. The DFWCS is designed to automatically control indicated steam generator water level at its setpoint, at plant power levels greater than 3%, using uncompensated main steam flow, main feedwater flow, and steam generator water level as inputs. Operation at 70% power is bounded by the 3% design specification. The main steam flow density-related bias error will not adversely impact the DFWCS.

Main Feedwater Flow Instruments

At 70% power, indicated feedwater flow will be 1.75% less than actual flow because of the higher liquid density at the feedwater venturis at 70% power compared to the venturi liquid density assumed for transmitter calibration. Since the COLSS feedwater flow algorithm compensates for the density variation that creates this bias error, the feedwater secondary calorimetric result (FWBSCAL) is not impacted by the error. The uncertainty in FWBSCAL becomes larger as power level drops as addressed in the response to RAI 12.

Steam Generator Blowdown Flow Instruments

At 70% power, the indicated volumetric steam generator blowdown flow will be 0.41% less than actual volumetric flow (assuming all other error contributors are zero) because of the higher liquid density at the blowdown orifice plates at 70% power compared to the orifice plate liquid density assumed for transmitter calibration. The calibrated range of the steam generator blowdown flow indicators is 0 to 350 gpm. Steam generator blowdown flow is limited by the blowdown processing system design to approximately 275 gpm per steam generator. Normal flow is maintained within the range of approximately 200 to 250 gpm per steam generator. With the blowdown bypass system in service, steam generator blowdown flow is directed to the plant circulating water discharge; maximum blowdown flow during this mode of operation is limited to 200 gpm per steam generator. At these flow values, the 0.41% bias error at 70% power corresponds to an indication error of approximately 1 gpm (indicated flow lower than actual flow) which will have no adverse impact on either blowdown processing system operation or blowdown bypass system operation. The blowdown flow parameter is an input to the COLSS secondary calorimetric. The 0.41% error in blowdown flow (actual flow greater than indicated flow) is approximately 0.01% of feedwater flow. The impact of the blowdown flow bias error on the COLSS secondary calorimetric result is insignificant because the error is minute compared to the feedwater flow term, the major input to the calorimetric power computation.

Steam Generator Narrow-Range Water Level Instruments

A bias error is introduced into the steam generator NR water level measurements whenever the plant operates at power levels less than 100%. The bias error is negative; i.e., indicated water level will be less than actual water level. The densities of the steam generator saturated liquid and vapor and subcooled downcomer water vary with steam generator saturation pressure and main steam flow (i.e., plant power level) to create the measurement bias error. The error is present over the entire measurement range but varies with water level. Its magnitude is greatest at the high end of the calibrated range and least at the low end of the range. At 70% power with actual level at the high end of the range, the bias error is approximately -2.0% of span. At the low end of the range, the bias error is approximately -1.0% of span. The bias error affects both indication and control. At the normal operating water level (68.2% NR), the bias error is approximately -1.75%. Actual water level will be approximately 70% NR when indicated level is at the 68.2% control point (assuming all other error contributors are zero).

Plant Protection System Setpoints

The uncertainties and setpoint margins associated with the various Unit 2 PPS trips and alarms were reviewed for potential impacts due to reduced-power operation and increased tube plugging during operating cycle U2C17. The work included preparation of a new uncertainty/setpoint margin calculation for the steam generator NR water level PPS trips and alarms and a review of the existing uncertainty/setpoint margin calculation for all other PPS trips

and alarms. The new NR water level uncertainty/setpoint margin calculation and the parallel review of the existing PPS uncertainty/setpoint margin calculation confirmed that the installed PPS setpoints for Unit 2 are acceptable with 550°F full-power T_{COLD} from hot zero power to 100% power with up to 8% tube plugging.

The negative bias error in indicated steam generator NR water level that exists at 70% power results from the changes in steam generator saturation pressure that accompany plant power level changes. For the steam generator NR water level PPS setpoints that address decreasing level (e.g., the low-level reactor trip setpoint at 21% of span), the negative bias error is conservative. With the bias error produced at 70% power and with indicated water level at the low-level setpoint, actual level in the vessel will be above the 0.0% of span low-low analysis value used in the safety analyses (i.e., the low-low analysis value bounds the worst-case actual level at 70% power). Since the concern for the low-level setpoints is too little water volume above the vessel lower instrument tap, the extra water is beneficial. For the PPS setpoints that address increasing level (e.g., the high-level reactor trip setpoint at 89% of span), the bias is non-conservative. For the high-level trip, actual water level in the vessel with the error present will be higher than indicated level and closer to flooding the vessel upper instrument tap. If the upper tap becomes flooded, further increases in actual level cannot be seen because the additional head is applied equally to both the transmitter variable leg and the transmitter reference leg. Indicated level reaches its maximum value when actual level reaches the elevation of the upper tap. The high-level trip provides protection during the excessive feedwater malfunction transient to prevent overfilling the steam generators and turbine damage. The setpoint is 11% of span below the upper tap to provide assurance that the trip will occur before the upper tap floods, even if actual instrument channel error at the time is as large as the calculated maximum total loop uncertainty. The pressure variation bias error at 70% power is bounded by the pressure variation bias error that is produced during the excessive feedwater event. The negative bias error at 70% power does not adversely impact the high-level trip function. Actual steam generator water level will be at or below the vessel upper instrument tap when indicated level reaches the high-level trip setpoint. The trip condition will be correctly sensed and processed.

Differential pressure transmitters across the primary side of the steam generators provide the inputs for the PPS RCS low-flow trips. Westinghouse was contracted by SCE to evaluate the impact due to reduced-power operation and tube plugging on the RCS low-flow trip setpoints. The resulting Westinghouse evaluation concluded that the existing RCS low-flow trip setpoints remain acceptable for steam generator differential pressure (ΔP) values between 27 psid and 45 psid with flow noise up to 2 psid peak-to-peak. In the event the peak-to-peak flow noise value would exceed 2 psid, then the maximum permissible steam generator differential pressure (45 psid) would have to be decreased proportionately. Post tube-plugging steam generator ΔP signal sampling confirmed that flow noise will be less than 2 psid peak-to-peak when Unit 2 is placed back into service. The average ΔP values in the eight instrument channels ranged from approximately 35 psid to approximately 38 psid, about midway in the 27 psid to 45 psid band specified by Westinghouse. The maximum peak-to-peak noise signal in any of the channels during the sampled period was 1.5130 psid. This observation confirmed that the flow noise limit identified in the Westinghouse evaluation (2 psid peak-to-peak) will not be exceeded when Unit 2 is returned to service.

Pressurizer Level Setpoint Programs and RCS Reference Temperature Programs

The pressurizer level setpoint programs and the T_{REF} programs run on discrete controllers. Each program adjusts its output (pressurizer level setpoint or T_{REF}) in response to plant power

level changes. Within the pressurizer level setpoint program, the computed RCS average temperature (T_{AVE}) parameter is used as the measure of plant power. The T_{REF} program uses the high-pressure (HP) turbine first-stage pressure parameter for the power input.

The HP turbine first-stage pressure versus power profile for restored T_{COLD} (550°F at full-power) is not changed by the 70% power limitation proposed for the U2C17 operating cycle. A given power output requires a specific HP turbine first-stage pressure. Consequently, there will be no impact to the T_{REF} controller output. No changes are needed in the T_{REF} controller configurations to support reduced-power operations.

At 70% power, plugging 8% of the steam generator tubes has the effect of increasing T_{AVE} from 568.1°F to 568.7°F and will consequently change the pressurizer level setpoint program output from 48.86% of the pressurizer level instrument span to 49.18% of span, an increase of 0.32% of span. With the current 2% and 3% tube plugging ratios in the Unit 2 steam generators, the actual pressurizer level setpoint shift going into the U2C17 operating cycle will be even smaller than the insignificant 0.32% value for 8% tube plugging. No changes are needed in the pressurizer level setpoint controller configurations to support reduced-power operations with tube plugging ratios up to 8%.

Nuclear Steam Supply System Control Systems

Westinghouse previously analyzed the nuclear steam supply system (NSSS) control system configurations for the T_{COLD} restoration project, which changed full-power T_{COLD} to 550°F. The analysis provided new values for the NSSS control system calibrations (including values for the DFWCS and the SBCS). The new calibration values were installed during the R2C17 outage. As part of the Unit 2 return-to-service effort, the NSSS control system configurations were reviewed again to identify potential impacts from operating at reduced power for an extended period with steam generator tube plugging ratios up to 8%. The review found the installed NSSS control system configurations for 550°F full-power T_{COLD} to be acceptable from hot zero power to 100% power with up to 8% tube plugging.