149 FERC ¶ 61,061

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, and Tony Clark.

Southern California Edison Company   Docket No. IN14-8-000

ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued October 21, 2014)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) between the Office of Enforcement (Enforcement), the North American Electric Reliability Corporation (NERC), and Southern California Edison Company (SCE). This order is in the public interest because it resolves on fair and reasonable terms an investigation of SCE, conducted by Enforcement in coordination with NERC and the Commission's Office of Electric Reliability (OER), into possible violations of Reliability Standards associated with SCE's operation of a portion of the Bulk Power System (BPS) and a blackout that occurred on September 8, 2011. SCE agrees to pay a civil penalty of $650,000, of which $250,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $400,000 will be invested in reliability enhancement measures that go above and beyond mitigation of the violations and the requirements of the Reliability Standards. SCE also agrees to commit to mitigation and compliance measures necessary to mitigate the violation described in this Agreement, and to make semi-annual compliance reports to Enforcement and NERC for at least one year.

I. Background

2. SCE, a wholly-owned subsidiary of Edison International, is an investor-owned utility providing electricity in central, coastal, and southern California. Among other NERC registrations, SCE operates as a Transmission Owner (TO) and Operator (TOP) within the California Independent System Operator's (CAISO) Balancing Authority area, and has delegated part of its responsibilities as TOP to CAISO under a Coordinated Functional Registration. SCE owns approximately 5,490 circuit miles of transmission lines, including 500, 230, and 161 kV lines. At the time of the event, SCE owned more than 5,600 MW of generation, including a majority share in the San Onofre Nuclear Generating Station (SONGS) in Southern California.[1] SCE's peak load exceeds 22,000 MW. SCE is subject to the Commission's regulation under section 215 of the Federal Power Act (FPA).[2]

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[1] In June 2013, SONGS permanently ceased power operations.

[2] 16 U.S.C. § 824o (2012).

3. On March 16, 2007, in Order No. 693,[3] the Commission approved the initial Reliability Standards, which became mandatory and enforceable within the contiguous United States on June 18, 2007.

4. The investigation of SCE arose out of a system disturbance that occurred on the afternoon of September 8, 2011 in the Pacific Southwest, which resulted in cascading outages and left approximately 2.7 million customers (equivalent to five million or more individuals) without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service Company's Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through Imperial Irrigation District's (IID) service territory, into Southern California.

5. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

6. These redistributed flows traveled through IID's and Western Area Power Administration-Desert Southwest's (Western-DSW) facilities, onto Western Electricity Coordinating Council (WECC)[4] Path 44, an aggregation of five 230 kV transmission lines that deliver power in a north-south direction from SCE's territory in Los Angeles to San Diego. The increased power flows parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions, voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading on Path 44 initiated an intertie separation scheme owned and operated by SCE at

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[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[4] At the time of the event, WECC was registered with NERC as the Reliability Coordinator (RC) for all of the entities affected by the event, as well as serving as the Regional Entity (RE) under a delegation agreement with NERC. Since the event, the Regional Entity and Reliability Coordinator functions have been bifurcated, with WECC remaining the Regional Entity, and Peak Reliability becoming the independent Reliability Coordinator. *See Order on Compliance*, 146 FERC ¶ 61,092 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation).

the San Onofre switchyard. Initiation of this intertie separation scheme separated San Diego Gas & Electric (SDG&E) from Path 44, contributed to tripping the SONGS nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's (CFE) Baja California Control Area in Mexico.

7. Before the September 8 event, system conditions had never exceeded the threshold for triggering the intertie separation scheme at the San Onofre switchyard, and SCE had never conducted any studies to assess the scheme's impact on reliability or the scheme's impact on an already severely compromised system.

8. Operation of the scheme simultaneously opened all five 230 kV transmission lines—Path 44—connecting SCE and SDG&E, as it was designed to do, and the resulting cut in power to SDG&E's system caused a rapid frequency decline indicative of a severe imbalance between generation and load in SDG&E's system. This rapid frequency decline affected SDG&E's Underfrequency Load Shedding (UFLS) program. Prior to this point in the event, SDG&E had already lost its intertie to the east, and with the opening of Path 44, SDG&E was effectively separated from the rest of the Western Interconnection.

9. The operation of the separation scheme under the extreme power flow conditions resulted in a sudden change in the angle of the generator rotors at SONGS. This resulted in the activation of turbine control logic to prevent over speed of the equipment which tripped both SONGS units.

II. Investigation

10. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the BPS were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[5] The Report discusses a detailed sequence of events, simulations, and findings related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational

[5] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

awareness, consideration of bulk electric system (BES) equipment, System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs), and protection systems.

11. Following publication of the Report, Enforcement, OER, and NERC staff reviewed the data gathered during the inquiry for compliance implications. At the direction of the Commission, Enforcement initiated non-public investigations of several entities, including SCE, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014), which were conducted jointly with NERC.

12. Enforcement and NERC determined that SCE violated the Protection and Control (PRC-) group of Reliability Standards. The PRC standards cover a range of topics related to the protection and control of power systems, including the design, coordination, and maintenance of functional protection systems.

13. Enforcement and NERC determined that SCE failed to adequately coordinate the intertie separation scheme at the San Onofre switchyard with protection systems, including (1) the acceleration limits within the turbine control systems on the two SONGS generators; and (2) the UFLS program of its neighbor, SDG&E, in violation of Reliability Standard PRC-001-1 R4. Enforcement and NERC found SCE's violation to be a serious deficiency undermining reliable operation of the BPS.

III. Stipulation and Consent Agreement

14. Enforcement, NERC, and SCE resolved this matter by means of the attached Agreement. SCE stipulates to the facts recited in the Agreement and agrees to pay a civil penalty of $650,000, of which $250,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $400,000 will be invested in reliability enhancement measures that go above and beyond the requirements of the Reliability Standards, as described in the Agreement. SCE neither admits nor denies that its actions constituted violations of the Reliability Standards.

15. SCE also agrees to additional mitigation measures, and to submit to compliance monitoring, as specified in the Agreement.

16. In consideration of the appropriate sanction, Enforcement considered that SCE has made significant efforts to date to address reliability concerns identified in the inquiry and investigation and also by SCE on its own initiative. SCE also fully and comprehensively cooperated with Enforcement and NERC during the investigation.

IV. Determination of the Appropriate Sanctions

17. The civil penalty amount is consistent with the Penalty Guidelines.[6] Enforcement considered that the event caused a loss of 10,000 or more MWh of firm load, and SCE

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[6] *Enforcement of Statutes, Orders, Rules and Regulations,* 132 FERC ¶ 61,216 (2010).

was allocated a share of the base penalty. The civil penalty amount reflects credit for SCE's full cooperation during the course of the investigation as well as credits for avoiding a trial-type hearing and having an effective compliance program.

18. The Commission concludes that the penalties and other sanctions set forth in the Agreement are a fair and equitable resolution of this matter and are in the public interest. The Commission also concludes that the reliability enhancement measures set forth in the Agreement will enhance the reliability of the BPS and are therefore also fair and in the public interest.

The Commission orders:

The attached Stipulation and Consent Agreement is hereby approved without modification.

By the Commission. Commissioner Bay is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company) Docket No. IN14-8-000

STIPULATION AND CONSENT AGREEMENT

I. INTRODUCTION

1. Staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission (Commission), the North American Electric Reliability Corporation (NERC), and Southern California Edison Company (SCE) enter into this Stipulation and Consent Agreement (Agreement) to resolve a non-public investigation conducted by Enforcement and NERC pursuant to Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014). The investigation examined possible violations of NERC Reliability Standards by SCE related to a system event in the Pacific Southwest on September 8, 2011 (September 8 event or event). SCE neither admits nor denies that it violated the Reliability Standard described in the Agreement, but agrees to pay a total civil penalty of $650,000, of which $250,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $400,000 will be invested, subject to Enforcement and NERC approval, by SCE in reliability enhancement measures identified below that go above and beyond the Agreement's mitigation commitments or what that Reliability Standards require (Reliability Enhancements). SCE also commits to mitigation and compliance measures, subject to compliance monitoring, as detailed in the Agreement.

II. STIPULATED FACTS

2. Enforcement, NERC, and SCE hereby stipulate and agree to the following facts.

A. SCE

3. SCE, a wholly-owned subsidiary of Edison International, is an investor-owned utility providing electricity in central, coastal, and southern California. Among other NERC registrations, SCE operates as a Transmission Owner (TO) and Operator (TOP) within the California Independent System Operator's (CAISO) Balancing Authority area, and has delegated part of its responsibilities as TOP, including seasonal, next-day, and current-day planning, to CAISO under a

Coordinated Functional Registration.[1] SCE owns approximately 5,490 circuit miles of transmission lines, including 500, 230, and 161 kV lines. At the time of the event, SCE owned more than 5,600 MW of generation, including a majority share in the San Onofre Nuclear Generating Station (SONGS) in Southern California.[2] SCE's peak load exceeds 22,000 MW.

B. Event Description

4. During an 11-minute period on the afternoon of September 8, 2011, a system disturbance occurred in the Pacific Southwest, resulting in cascading outages and leaving approximately 2.7 million customers without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service's (APS's) Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through the service territory of Imperial Irrigation District (IID), into Southern California.

5. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

6. These redistributed flows traveled through IID's and Western Area Power Administration – Desert Southwest's (Western-DSW's) territories onto Western Electricity Coordinating Council (WECC)[3] Path 44, an aggregation of five 230 kV

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[1] JRO00009 was originally entered into on September 11, 2008 and most recently updated on May 24, 2012. JRO00009 delineates compliance responsibility for the Standards and Requirements associated with the TOP function between CAISO and SCE.

[2] In June 2013, SONGS permanently ceased power operations.

[3] At the time of the event, WECC was registered with NERC as the Reliability Coordinator (RC) for all of the entities affected by the event, as well as serving as the Regional Entity (RE) under a delegation agreement with NERC. Since the event, the Regional Entity and Reliability Coordinator functions have been bifurcated, with WECC remaining the Regional Entity, and Peak Reliability becoming the independent Reliability Coordinator. *See Order on Compliance*, 146 FERC ¶ 61,092 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation). The Agreement will

transmission lines that deliver power in a north-south direction from SCE's territory in Los Angeles to San Diego Gas & Electric (SDG&E). The increased power flows parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions, voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading on Path 44 initiated an intertie separation scheme, owned and operated by SCE, located at the San Onofre switchyard.[4] CAISO is responsible for many of the TOP functions for SCE under a Coordinated Functional Registration. Initiation of the intertie separation scheme at the San Onofre switchyard separated SDG&E from Path 44, contributed to tripping the SONGS nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's Baja California Control Area.

7. SCE's role in the September 8 event centers on its ownership and operation of the intertie separation scheme at the San Onofre switchyard that initiated approximately 10 minutes and 40 seconds into the 11-minute event. Operation of the scheme simultaneously opened all five 230 kV transmission lines—Path 44—connecting SCE and SDG&E, as it was designed to do, and the resulting cut in power to SDG&E's system caused a rapid frequency decline indicative of a severe imbalance between generation and load in SDG&E's system. This rapid frequency decline affected SDG&E's Underfrequency Load Shedding (UFLS) program. Prior to this point in the event, SDG&E had already lost its intertie to the east, and with the opening of Path 44, SDG&E was effectively separated from the rest of the Western Interconnection. Before the September 8 event, system conditions had never exceeded the threshold for triggering the intertie separation scheme at the San Onofre switchyard, and SCE had never conducted any studies to assess the scheme's impact on reliability or the scheme's impact on an already severely compromised system.

8. The operation of the separation scheme under the extreme power flow conditions resulted in a sudden change in the angle of the generator rotors at SONGS. This resulted in the activation of turbine control logic to prevent over speed of the equipment which tripped both SONGS units.

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refer to WECC when relevant to the event, and will otherwise refer to the relevant function (RE or RC) rather than using the entity names WECC or Peak Reliability.

[4] Since the September 8 event, Enforcement and NERC have referred to this intertie separation scheme as the SONGS Separation Scheme.

III. INQUIRY AND INVESTIGATION

9. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the Bulk-Power System (BPS) were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[5] The Report discusses a detailed sequence of events, simulations, and findings related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational awareness, consideration of Bulk Electric System (BES) equipment, system operating limits (SOLs) and Interconnection Reliability Operating Limits (IROLs), and protection systems.

10. Following publication of the Report, Enforcement and NERC reviewed the data gathered during the inquiry for compliance implications. As a result of that review, Enforcement and NERC initiated non-public investigations of several entities, including SCE, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2014). Enforcement and NERC determined that SCE violated Reliability Standard PRC-001-1 R4 and found that this violation undermined the reliability of the BPS and contributed to the September 8 event. Enforcement and NERC recognized, however, that after the event, and during the inquiry and investigation, SCE voluntarily began making improvements in its planning and operations, and implementing recommendations from the Report, that addressed many of the findings arising from the Report. In addition, SCE fully cooperated with Enforcement and NERC during the investigation.

11. As part of the investigation, Enforcement and NERC reviewed SCE's compliance program and discovered that SCE satisfies the criteria for an effective compliance program under the Commission's Penalty Guidelines.[6] Enforcement

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[5] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[6] *Enforcement of Statutes, Orders, Rules and Regulations*, 132 FERC ¶ 61,216, § 1B2.1 (2010).

and NERC considered the following elements of SCE's compliance program: (1) SCE's NERC Compliance Program office is staffed by seventeen full time employees devoted to ensuring compliance with each Reliability Standard; (2) SCE conducts an annual self-assessment of its overall NERC compliance as well as monthly assessments of compliance with specific Reliability Standards; (3) Five of SCE's senior Officers are a part of SCE's NERC Executive Steering Team (EST). The EST team members are fully engaged in the compliance program and attend monthly status meetings with the director of the compliance program; and (4) SCE employees attend annual training sessions on NERC compliance and have opportunities to report and raise compliance issues, including through an anonymous Hotline maintained by a third party.

IV. VIOLATION

12. Enforcement and NERC determined that SCE violated Reliability Standard PRC-001-1 R4 because prior to the September 8 event it did not adequately coordinate the intertie separation scheme at the San Onofre switchyard with protection systems, including (1) the acceleration limits within the turbine control systems on the two SONGS generators; and (2) the UFLS program of its neighbor, SDG&E. Prior to the event, SCE had not conducted studies to assess the scheme's impact on reliability. Prior to the event, SCE also had not conducted studies to assess the scheme's impact on the acceleration of the SONGS units, or the impact to an already severely compromised system. As a result, SCE did not know how the initiation of the scheme would impact reliability, including whether the scheme would result in the tripping of the SONGS generators or how it might affect the ability of SDG&E's UFLS program to arrest extreme frequency decline, as described in paragraphs 6, 7, and 8 above.

V. REMEDIES AND SANCTIONS

13. SCE stipulates to the facts as described in Section II of the Agreement, but neither admits nor denies Enforcement's and NERC's findings that its conduct violated the Reliability Standard specified in Section IV. For purposes of settling any and all civil and administrative disputes within the jurisdiction of the Commission arising from reliability issues related to the September 8 event and Enforcement and NERC's investigation, SCE agrees to the remedies set forth in the following paragraphs.

A. Civil Penalty

14. SCE shall pay a total civil penalty of $650,000, of which $250,000 shall be paid, divided in equal amounts, to the United States Treasury and NERC within ten days of the Effective Date of the Agreement. Enforcement and NERC agree to give SCE a partial civil penalty offset for the remaining $400,000 in exchange for

SCE agreeing to implement the Reliability Enhancements set forth in Section V.B. The value of the Reliability Enhancements is expected to substantially exceed the amount of the offset.

B. Reliability Enhancements

15. In exchange for the $400,000 offset, as Reliability Enhancements, SCE shall provide the RE and/or RC with three Full-Time Equivalent (FTE) technical employees for a total of 6,240 hours to assist the RE and/or RC with their efforts in response to the September 8 event.

16. As part of the Reliability Enhancements, SCE employees will participate in regional study groups and various RE, RC, and/or NERC reliability initiatives, created in response to and for the purpose of improving reliability after the September 8 event. SCE, the RE, and/or RC will agree on the skill set of the employees to be shared and the employees' projects and tasks.

17. The scope and nature of the projects and tasks to be performed by the aforementioned SCE employees shall be approved by Enforcement and NERC, such approval not to be unreasonably withheld. SCE shall complete the Reliability Enhancements by December 31, 2016.

18. If SCE has not performed the Reliability Enhancements by December 31, 2016, or determines, prior to December 31, 2016, that it cannot reach an agreement with the RE and/or RC on the projects or tasks to be performed, SCE shall subtract from $400,000 the cash value of the services, if any, already performed, and pay the remaining sum in equal shares to the United States Treasury and NERC. The calculation of the sum due to Treasury and NERC, including the cash value of the services, and the identification of the services to be credited, are subject to review and approval by Enforcement and NERC.

C. Completed and Required Mitigation

19. SCE commits to the following actions, designed to mitigate the Reliability Standard violations and to improve overall reliability of the BES. As indicated below, SCE affirms that it has already completed most of the mitigation measures and shall complete all remaining mitigation measures no later than December 31, 2015, unless otherwise stated in this Section. In those instances where SCE has already implemented mitigation measures prior to entering into the Agreement, it shall continue operating under the practices and procedures implemented as part of the mitigation, until such time as it implements improved practices and procedures, as determined by Enforcement and NERC. SCE will report on the status of all mitigation measures described in this Section and submit evidence of

status and progress in its compliance monitoring reports to be submitted to Enforcement and NERC pursuant to Section V.C of the Agreement.

i. Mitigation Related to Protection Systems

Protection System Coordination[7]

20. SCE has completed multiple mitigation measures and has also agreed to implement multiple additional mitigating measures aimed at improving its coordination of Covered Protection Systems, including intertie overload separation schemes.[8]

21. Following the September 8 event, SCE undertook an expedited technical and physical evaluation of all its intertie overload separation schemes, to ensure that such schemes and the schemes' settings were properly coordinated across its transmission system. Based on this evaluation and to the extent necessary to ensure proper coordination, SCE changed the settings on some schemes, and disabled and removed others.

22. In addition to any requirements under the Reliability Standards related to protection systems, starting in 2014, SCE agrees to conduct a detailed study of twenty percent of its existing and planned Covered Protection Systems each year with 100 percent of the studies to be completed by December 31, 2018. SCE will prioritize its assessment of intertie overload separation schemes and will complete its assessment of such schemes by December 31, 2015. This assessment shall consider (1) the purpose and limitations of Covered Protection Systems; (2) the necessity of Covered Protection Systems; (3) the classification of Covered Protection Systems; (4) coordination of Covered Protection Systems with other devices and systems; (5) impact of Covered Protection Systems on internal and external elements; (6) whether Covered Protection Systems have unintended reliability consequences; (7) whether SCE's Underfrequency Load Shedding program is effective and consistent with the RE's Off-Nominal Frequency Load

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[7] This section on Protection System coordination applies to the following Protection Systems: (1) internal to SCE's system, Special Protection Systems (including intertie overload separation schemes), overload Protection Systems on transmission equipment, and overload Protection Systems that studies show affect the BPS; and (2) external to SCE's system, Protection Systems that are known to affect SCE's operations (referred to as "Covered Protection Systems").

[8] SCE has identified its intertie overload separation schemes that remain in service, and Enforcement, NERC, and SCE maintain a list of such schemes confidentially.

Shedding plan; and (8) affected generators' response to activation of Covered Protection Systems.

23. SCE further agrees to share relevant information, including Covered Protection System settings, from the foregoing assessments with impacted entities and the Reliability Coordinator. To the extent SCE learns from the assessments that any Covered Protection Systems have degraded or have the potential to not operate as designed, SCE will immediately share this information with impacted entities and the Reliability Coordinator.

Effect of Protection Systems on Transmission Facility Loadability

24. SCE agrees to implement mitigation measures aimed at ensuring that its protection system relay settings do not limit the loadability of its transmission facilities. Specifically, in its 2016 Annual Transmission Reliability Assessment, and each year thereafter, SCE will review its transmission facility SOLs to ensure that they account for protection system relay settings and that they are equal to the most limiting operating criteria during all timeframes, including restoration. SCE will also identify instances where its relay trip points are set too close to transmission facility emergency ratings and to develop plans to mitigate such instances.

Protection System Training

25. SCE agrees to broaden its protection system training program. SCE has provided its transmission operators training on internal protection systems since before the September 8 event. Within six months of the Effective Date of the Agreement, SCE agrees to review this training to ensure it covers the purpose and limitations of Covered Protection Systems, the settings of Covered Protection Systems, and the impact of Covered Protection Systems on internal and external elements. SCE also agrees to expand this training within one year of the completion of the assessment described in Paragraph 22 to cover external protection systems, as identified by SCE, the CAISO, or any adjacent entity, that are likely to impact SCE's system reliability.

ii. Mitigation Related to Long-Term Planning

Consideration of Critical System Conditions in Long-Term Planning Assessments

26. Within one year of the Effective Date of the Agreement, SCE agrees to implement several steps (described below in paragraphs 27-30) to ensure that its long-term planning assessments consider critical system conditions, including expected system transfers above firm, expected internal and external generation dispatch, the impact of internal and external facilities, transmission facilities

operated below 100 kV, local distribution facilities operated below 100 kV that are known to impact the BPS, and the impact of active protection and control devices.

27. Regarding expected system transfers above firm, SCE agrees to include in its long-term studies additional sensitivities by varying generation and load to stress system transfers.

28. To ensure it considers expected internal and external generation dispatch levels in its long-term planning studies, SCE agrees to simulate combinations of various generator outages in its transmission area as well as neighboring areas that could impact its system.

29. SCE also agrees to improve its long-term planning process by ensuring that it considers internal and external facilities operated below 100 kV, where those facilities operate in parallel with facilities above 100 kV or have the potential to affect BPS reliability.[9] For example, SCE agrees to begin utilizing the RE's new base case coordination system to develop cases that include 69 kV facilities and to monitor contingencies involving facilities operated at 69 kV and above in SDG&E's, IID's, and APS's territories that have an impact on SCE's system.

30. SCE agrees to update its contingency files of its various Special Protection Systems (SPS)/Remedial Action Schemes (RAS) for its annual long-term planning studies. Also, it will continue to support the work and respond to data requests of the RE's Modeling SPS and Relays Ad-hoc Task Force to incorporate selected relays into base cases.

Analyses and Benchmarking of Past Planning Studies

31. On a going forward basis, SCE agrees to benchmark annually the prior year's planning studies against actual system operating conditions and look and account for higher stress conditions not captured in its annual assessments, such as unusual generation and import patterns, higher than expected load patterns, and contingencies that may have occurred and were not evaluated. SCE agrees to share information from its benchmarking analyses with impacted entities, CAISO, and the Reliability Coordinator.

iii. Mitigation Related to Situational Awareness

Greater Coordination to Improve Situational Awareness

[9] Inclusion of transmission facilities operated below 100 kV in the mitigation measures pursuant to the Agreement shall have no effect on any current or future analysis regarding whether these facilities comprise part of the BPS.

32. SCE agrees to implement various mitigating measures to improve its coordination efforts with neighboring entities as a way of strengthening its situational awareness. When provided with additional system information for coordination, SCE will have greater capability to assess information, including in the next-day and real-time timeframes, that could impact its system.

33. When released by Peak Reliability for usage, SCE agrees to ensure that its operators and operating engineers utilize, on a daily basis, relevant elements of Peak Reliability's new data sharing portal, which contains next-day studies, historical archives, and data from the Western Interconnection Synchrophasor Project. When released for entity use by Peak Reliability the phasor measurement data will provide operators visibility of system conditions in near real-time and may enable early detection of problems that could lead to cascading outages.

<u>Expanded Situational Awareness</u>

34. To the extent SCE has not already done so, within six months of the Effective Date of the Agreement, SCE also agrees to undertake efforts to identify internal and external elements that impact its portion of the BPS, including facilities operated below 100 kV. In addition, to the extent it has not already done so, SCE agrees to identify all internal elements, including elements operated below 100 kV, that impact external BPS elements, and to notify impacted entities and the Reliability Coordinator of such elements. All such elements shall be included in its models for monitoring in its seasonal, next-day, current-day, and real-time studies. SCE has also received and continues to receive Inter-Control Center Communications Protocol (ICCP) data from neighbors to further improve its transmission models with real-time, verified data on facilities that impact its system.

<u>Response to Impaired Situational Awareness</u>

35. Within six months of the Effective Date of the Agreement, SCE agrees to improve its procedures for responding to the impairment of its monitoring capabilities. These procedures maintain plans for the loss of SCADA/EMS, RTCA, and the loss of communication. They also cover plans for communicating with the Reliability Coordinator and neighboring entities in case SCE loses situational awareness. SCE also agrees to revise its procedures governing the exchange of information regarding the loss or change in service status of critical facilities with the Reliability Coordinator and other impacted entities. SCE will complete operator training on all of these new processes within one year of the Effective Date of the Agreement.

D. Compliance Monitoring

36. SCE shall make semi-annual reports to Enforcement and NERC until all of the mitigation measures and Reliability Enhancements, identified in the Agreement, have been fully implemented and verified by Enforcement and NERC. The first semi-annual report shall cover the first six month period after the Effective Date of the Agreement and shall be submitted to Enforcement and NERC staff within thirty days of the expiration of that period. The subsequent report(s) shall be due in six month increments thereafter. Each report shall detail the following: (1) actions taken as of the date of the report to satisfy the terms of the Agreement, including all mitigation items and Reliability Enhancements; (2) actions taken to improve reliability compliance, including investments in new measures and training activities during the reporting period; and (3) any additional violations of Reliability Standards that have occurred and whether and how SCE has addressed those new violations. The reports must include an affidavit executed by an officer of SCE that the compliance reports are true and accurate and also include corroborative documentation or other satisfactory evidence demonstrating or otherwise supporting the content of these reports. Enforcement and NERC staff may require additional semi-annual reporting if circumstances indicate the need for further monitoring or if SCE has not yet completed all the mitigation measures described in this Section.

VI. TERMS

37. The "Effective Date" of the Agreement shall be the date on which the Commission issues an order approving the Agreement without material modification. When effective, the Agreement shall resolve all reliability matters relating to the September 8 event within the jurisdiction of the Commission, and that arose on or before the Effective Date, as to SCE or any affiliated entity.

38. Commission approval of the Agreement without material modification shall release SCE and forever bar the Commission and NERC from holding SCE, any affiliated entity, and any successor in interest to SCE liable for any and all administrative or civil claims arising out of the reliability issues related to the September 8 event or conduct addressed and stipulated to in the Agreement that occurred on or before the Agreement's Effective Date.

39. Failure to make timely civil penalty payments or to comply with the mitigation, Reliability Enhancements, and monitoring agreed to herein, or any other provision of the Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act (FPA), 16 U.S.C. §792, *et seq.,* and may subject SCE to additional action under the enforcement provisions of the FPA.

40. If SCE does not make the civil penalty payment described above at the time

agreed by the parties, interest payable to the United States Treasury and NERC shall begin to accrue pursuant to the Commission's regulations at 18 C.F.R. § 35.19(a)(2)(iii) (2014) from the date that payment is due, in addition to the penalty specified above and any other enforcement action and penalty that the Commission or NERC may take or impose.

41. The Agreement binds SCE and its agents, successors, and assignees. The Agreement does not create any additional or independent obligations on SCE, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in the Agreement.

42. The signatories to the Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer or promise of any kind by any member, employee, officer, director, agent or representative of Enforcement, NERC, or SCE has been made to induce the signatories or any other party to enter into the Agreement.

43. Unless the Commission issues an order approving the Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and Enforcement, NERC, and SCE shall not be bound by any provision or term of the Agreement, unless otherwise agreed to in writing by Enforcement, NERC, and SCE.

44. SCE agrees that the Commission's order approving the Agreement without material modification shall be a final and unappealable order assessing a civil penalty under the Federal Power Act. SCE waives findings of fact and conclusions of law, rehearing of any Commission order approving the Agreement without material modification, and judicial review by any court of any Commission order approving the Agreement without material modification.

45. The Agreement can be modified only if in writing and signed by Enforcement, NERC, and SCE, and any modifications will not be effective unless approved by the Commission.

46. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity and accepts the Agreement on the entity's behalf.

47. The undersigned representative of SCE affirms that he or she has read the Agreement, that all of the matters set forth in the Agreement are true and correct to the best of his or her knowledge, information and belief, and that he or she understands that the Agreement is entered into by Enforcement and NERC in express reliance on those representations.

48. The Agreement may be signed in counterparts.

49. The Agreement is executed in triplicate, each of which so executed shall be deemed to be an original.

Agreed to and accepted:

Larry D. Gasteiger
Acting Director, Office of Enforcement
Federal Energy Regulatory Commission

Date: October 2, 2014

Charles A. Berardesco
Senior Vice President, General Counsel and Corporate Secretary
North American Reliability Corporation

Date: 10/01/2014

Pete Dietrich
Senior Vice President , Transmission & Distribuition
Southern California Edison Company

Date: 09/22/2014

Document Content(s)