**BEFORE THE COUNCIL OF THE CITY OF NEW ORLEANS**

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| **APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF** | **)** | **DOCKET NO. UD-16-02** |

# DIRECT TESTIMONY

# OF

# PETER J. LANZALOTTA

**ON BEHALF OF**
**SIERRA CLUB, DEEP SOUTH CENTER FOR ENVIRONMENTAL JUSTICE,**
**AND THE ALLIANCE FOR AFFORDABLE ENERGY**

**PUBLIC VERSION**

October 16, 2017

**Q1. Mr. Lanzalotta, please state your name, position and business address.**

**A.** My name is Peter J. Lanzalotta. I am a Principal with Lanzalotta & Associates LLC, ("Lanzalotta"), 67 Royal Point Drive, Hilton Head Island, SC 29926.

**Q2. On whose behalf are you testifying in this case?**

**A.** I am testifying on behalf of the Sierra Club, the Deep South Center for Environmental Justice, and the Alliance for Affordable Energy, collectively the Joint Intervenors ("JI").

**Q3. Mr. Lanzalotta, please summarize your educational background and recent work experience.**

**A.** I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor of Science degree in Electric Power Engineering. In addition, I hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

I am currently a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, I was a partner of Whitfield Russell Associates, with which I had been associated since March 1982. My areas of expertise include electric system planning and operation. I am a registered professional engineer in the states of Maryland and Connecticut.

In particular, I have been involved with the planning and operation of electric utility systems as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities over a period exceeding thirty years.

I have presented expert testimony before the FERC and before regulatory commissions and other judicial and legislative bodies in 25 states, the District of Columbia, and the Provinces

of Alberta and Ontario. My clients have included utilities, state regulatory agencies, state ratepayer advocates, independent power producers, industrial consumers, the United States Government, environmental interest groups, and various city and state government agencies. A copy of my current resume is included as Exhibit PJL-1 and a list of my testimonies is included as Exhibit PJL-2.[1]

**Q4. What is the purpose of your testimony?**

**A.** I was retained to review portions of Entergy New Orleans' ("ENO" or the "Company") testimony related to its Supplemental Application to build the New Orleans Power Station ("NOPS") consisting either of a 226 MW combustion turbine ("CT") or, alternatively, seven internal combustion engine generator sets with a total of about 128 MW of capacity. My review focusses on the ability of transmission alternatives to NOPS to address reliability problems that are forecast to occur in the future.

The Company prefers to deal with these reliability problems by installing new generation at NOPS. My testimony will address the ability of transmission system reinforcements to address these reliability problems, the advantages of transmission reinforcements compared to the addition of generating capacity, and the weaknesses of the Company's arguments about why generation additions should be chosen over transmission reinforcements.

**Q5. What conclusions do you reach regarding these subjects?**

**A.** I conclude that i) a transmission alternative to NOPS will address the transmission system deficiencies the Company uses to try to justify NOPS and at a considerably lower capital cost, ii)

[1] Exhibit (PLJ-1) and Exhibit (PJL-2) as well as all other Exhibits referenced herein are attached to and incorporated by reference in this testimony.

the Company has not given thorough consideration to adding transmission capacity as an alternative to building NOPS, iii) the proposed location for NOPS at the location of the former Michoud generating units has flooded under major storm conditions, damaging the generating units that were located there at the time, iv) under major storm conditions, damage to generation located at NOPS, as well as damage to the distribution system have been correlated with damage to the transmission system, v) if the Company desires more reliability from the transmission alternative, beyond what rebuilding and reinforcing critical transmission lines would provide, a more thorough evaluation would have considered an underground transmission line to provide more reliability for the supply into the Company's service area, and vi) the Company has no need of black-start capacity to be provided by the proposed NOPS generation, considering current black-start capabilities that are available.

**Q6. What documents and materials did you review in the course of this engagement?**

**A.** I reviewed: i) the Company's direct and supplemental testimony and exhibits; and ii) responses to discovery by a number of parties to this proceeding.

**Q7. Why does the Company say it needs new generation at NOPS?**

**A.** The Company is attempting to justify its need for NOPS on several factors, one of which is to relieve future transmission overloads. The Company is subject to mandatory transmission planning requirements promulgated by the North American Electric Reliability Corporation ("NERC"). These mandatory planning requirements have led to the determination that overloads of some system components, and related reliability problems, can occur in the future unless the transmission system is reinforced or other system resources, such as generation, are added.

**Q8. What is the NERC and what does it do?**

**A.** The North American Electric Reliability Corporation (NERC) is a "not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel."[2]

Mandatory compliance with NERC Reliability Standards began on June 1, 2007. Compliance is mandatory, and penalties for violation of NERC Reliability Standards may be as high as $1 million per violation per day.

**Q9. Please describe how transmission system planning typically determines that transmission system reinforcements are needed.**

**A.** Transmission planning criteria formulated by NERC require that the effect of projected future peak loads[3] and the operation of existing and planned generation (less retirements) on existing and planned transmission system facilities, such as transmission lines and substation transformers, be studied to determine if such loads can be reliably served under normal conditions[4] and under prescribed contingency conditions.[5] If the loading of transmission system facilities in these studies under these conditions exceeds the capability of these facilities, or if the transmission system voltage levels become unstable or fall below or increase above specified

[2] http://www.nerc.com/Pages/default.aspx
[3] "Peak load" is the maximum or highest demand of electric power over an extended period of time.
[4] Normal conditions assume that all system facilities, such as transmission lines and substation transformers, are in service. Normal conditions can assume various levels of dispatch of existing generating units.
[5] Contingency conditions assume that one or more system facilities, such as transmission lines and substation transformers, are experiencing a forced (unplanned) outage. Contingency conditions can assume various levels of dispatch of existing generating units, including forced outages of generating units.

levels, then transmission system reinforcement is typically required. The relevant NERC transmission planning standard is called TPL-001-4, a copy of which in included as Exhibit PJL-4. ENO applies this NERC standard in conjunction with MISO and SERC criteria and Entergy's own planning criteria and provides the results to MISO for its analysis and consolidation into its transmission planning.[6]

The Company recently deactivated 2 generating units located at its Michoud site, removing some 781 MWs of generating capacity from service. The Company's service area is in a load pocket called Downstream of Gypsy ("DSG") which is an area of concentrated load which depends on local generation to serve a portion of its load at various times and under certain system conditions because of capacity limitations of the transmission lines connecting the load pocket with the rest of the system. Because of these generating unit retirements, this part of the Company's system requires additional resources in order to meet NERC-defined levels of reliability while serving its load as forecasted for the future. Such resources could take the form of increased transmission capacity, increased generation located in the DSG, net load reductions in the DSG due to distributed energy resources, demand management, and increased energy efficiency, or some combination of these.

The Company testifies that additional resource requirements begin as early as 2019[7], when transmission line overloads are projected to result under a number of different of different system conditions, including normal conditions and a number of contingency conditions. In the

[6] MISO refers to Midwest Independent System Operator, a Regional Transmission Operator. SERC refers to SERC Reliability Corporation (formerly the Southeast Electric Reliability Council), and is one of eight regional electric reliability councils under NERC authority.

[7] Although the Company's testimony uses the 2019 date for the start of reliability problems, discovery response indicate that reliability problems could occur in 2017 and 2018 as well. See the Company's response to Advisors 6-1.

most extreme contingency conditions, these overloads could cascade into multiple transmission line outages and a voltage collapse. These overloads are referred to NERC violations. The Company testifies that NERC violations of similar severity were found in the years 2022, 2024, and 2027.

The Company prefers to add generating capacity, but acknowledges the availability of transmission upgrade alternatives. Entergy admits that making transmission upgrades to five existing transmission lines would mitigate all the reliability-based system constraints over the next ten years without building new generation. These transmission upgrades are estimated to cost about $57.3 million[8], which compares favorably to the cost of the NOPS CT at $232 million and the cost of the alternate NOPS peakers at $210 million.

The Company tries to devalue the transmission-reinforcement approach by using the argument saying that the transmission alternative would diminish operation flexibility because scheduling planned outages of transmission facilities would be extremely difficult when nearly all transmission system elements are loaded near capacity. If the addition of more transmission capacity following the retirement of the former Michoud plant is needed to address transmission planning violations, this additional transmission capacity would also add to the transmission capacity available for the scheduling of planned maintenance on the transmission system.

**Q10. The Company states that, unless the NOPS is constructed, then electric system reliability in New Orleans would degrade, because NOPS has already been included in ENR's ten-year transmission planning horizon. Please comment.**

[8] See Supplemental Direct of Charles W. Long ("Long"), Table 1, p. 11.

**A.** NERC-required electric system transmission planning is an ongoing process which is repeated on a regular basis in order to take into account changes in system planning assumptions over time. Under the current assumptions, if NOPS is removed from the Company's future plans, then this planning process will accommodate changes in system facilities, such as transmission system reinforcements, so as to meet the requirements of NERC standards.

**Q11. The Company states that in 2019 there are potential reliability concerns. Will NOPS resolve those concerns? Could transmission be reinforced to resolve those concerns?**

**A.** Because the former Michoud generation was retired earlier than reflected in the Company's planning assumptions, there is a small chance of a cascading reliability problem in 2019 or earlier from specific contingencies. This would be prior to the completion of construction of any new NOPS generation or transmission reinforcements. Under these conditions, the Company states that it could use load shedding to avoid the contingency until construction was finished.[9]

**Q12. The Company attributes increased storm restoration benefits in the event of major storms to the construction of new generation at NOPS. Please comment.**

**A.** The Company states that having a generating unit that can produce real power in the DSG load pocket with the ability to start quickly could aid in shortening electric service restoration times after events such as hurricanes.[10] The Company hypothesizes that, if the transmission system suffers major damage during a hurricane, then having generation located at NOPS would enable it to supply local loads more quickly. Entergy's analysis ignores the fact that a hurricane strong enough to produce major damage to the transmission system also poses the threat of

[9] See the Company's response to Advisors 6-1, Exhibit PJL-7.
[10] Long Direct at 13: 7-9.

significant damage to generating units in the DSG. Additionally, distribution facilities are typically more susceptible to wind damage than are transmission lines and if local distribution facilities are heavily damaged by a major storm, this will reduce the electric load that can be served by any generation located there that happens to survive the storm. The same will be true of the susceptibility to damage of transmission facilities that are located entirely within the DSG.

For example, during Hurricane Katrina, the generating units installed at the Michoud site in the DSG all suffered significant damage. Michoud unit 1 suffered enough damage that it was not economic to repair the unit, so it was never repaired. Michoud units 2 and 3 were repaired, at a cost of $10.7 million. It took 6 weeks to repair Michoud unit 2 and return it to service, and 16 weeks to repair Michoud unit 3.[11]

As an example of how heavy winds strong enough to damage transmission lines can also damage the distribution system was provided during Hurricane Gustav in the fall of 2008. **START HSPM** [redacted][12] **STOP HSPM** The Company describes that the transmission lines that tripped during Gustav formed a load pocket that included the DSG and which resulted in no loss of load. There was sufficient generation to supply the load pocket, which the Company says mitigated against widespread outages.[13] **START HPSM** [redacted]

[11] See the Company's response to AAE 8-12, Exhibit PJL-8.
[12] See the Company's response to SIE 5-1 (c).
[13] See the Company's response to SIE 5-1 (b), Exhibit PJL-9. While there was generation still located at the Michoud site during Gustav, there are no reports that it helped support the load pocket that formed during the storm.

[redacted]

[redacted] **STOP HPSM**

**Q13. The Company bases much of its justifications for new generation at NOPS on the potential loss of or shortage of transmission capacity into the DSG under storm conditions. Please discuss whether the Company has considered the installation of underground transmission into the DSG as a way of increasing the transmission capacity into DSG and of increasing its resilience of that transmission capacity under storm conditions.**

**A.** The Company did not give serious consideration to an underground transmission option, so it doesn't know to what extent such facilities are feasible. The Company tries to justify this position by saying:

However, it is well known that the expected incremental cost of restoration of overhead transmission facilities does not justify the cost of underground transmission construction and nor does the cost of underground conversion of overhead to underground transmission conversion justify the benefits received from doing so. [14]

The Company attaches a 3 page excerpt[15] from a 106 page report from the Texas PUCT that it uses to base its conclusion that underground transmission is infeasible. What the study segment seems to say is that it is not economically justifiable to underground transmission lines that are within 50 miles of the Texas coast because the probability of damage is relatively low and the cost to repair them if they are damaged are also relatively low. I note that the Company's

[14] See the Company's response to AAE 8-19, Exhibit PJL-3.
[15] Attached to the Company's response to AAE 8-19, Exhibit PJL-3.

proposed generation alternatives both have capital costs well in excess of $200 million, while the Company has not developed costs for an underground alternative.

**Q14. The Company attributes black-start benefits to the installation of new generation at NOPS. Please comment.**

**A.** Black-start capability is the ability of a generating unit to start up without access to an outside source of power and generate power to be used to recover from a system blackout. I note that the Company describes its existing black start procedures as being "certainly robust and sufficient to provide power to the Company's customers if a complete loss of electric power supply were to occur…."[16] The Company goes on to say that these procedures still rely on transmission facilities to import power into ENO. If these transmission facilities are reinforced and/or augmented rather than building NOPS, the Company's ability to import power into the DSG would be increased and its susceptibility to any contingency or contingencies would likely be reduced.

**Q15. The Company criticizes the transmission alternative because transmission line rights of way are scarce and transmission line construction conditions are difficult in and around ENO's service area. Please comment.**

**A.** I note that the Company has not yet seriously studied the rebuild of the five existing transmission lines it says are needed for system reliability if no generation is built at NOPS. Therefore, the Company doesn't know if any new transmission rights of way will be needed, or to what extent the existing transmission line towers will have to be rebuilt. While these are characteristics that could increase the cost of new or rebuilt transmission facilities, they should

[16] Long Supplemental Direct at 28:19-21.

not rule out transmission as an alternative to new generation at NOPS prior to a more thorough analysis.

**Q16. The Company attributes some of the post contingency reliability problems of the existing electric system in and around DSG to voltage collapse due a shortage of reactive power. Please comment.**

**A.** A voltage collapse of the type is typically driven by a shortage of reactive power. Reactive power is a component of electric power that is required to supply inductive loads, such as air conditioning compressors, elevator drives, and industrial motors. Frequently, devices such as capacitors are used to provide additional voltage support in times of need.

The voltage stability analysis the company performed at the retirement of Michoud unit 3[17] found no voltage concerns. I note that, if the required transmission line reinforcements for the no-NOPS scenario are performed, the Company has not indicated that additional sources of reactive power are needed to meet NERC requirements.

If reactive power does become a concern, there are approaches other than generation to help control system voltage and to provide a very fast response to system voltage changes caused by faults or other causes. Attached as Exhibit PJL-5 is a description of a piece of equipment called static var compensator ("SVC"). This equipment monitors and supports electric system voltage through reactive power management. As described in Exhibit PJL-5:

SVC is the preferred tool for dynamic reactive power support in high voltage transmission grids. Thanks to its inherent capability for high-speed, cycle-by-cycle control of

[17] See Appendix B of Attachment Y, Long Direct Testimony at Exhibit CWL-5.

vars, it will counteract the often hazardous voltage depressions that follow in conjunction with faults in the grid.[18]

Another candidate to help control system voltage and to provide a very fast response to system voltage changes caused by faults or other causes is called a STATCOM, short for static compensator, which is a class of SVC. Attached as Exhibit PJL-6 is a description of the use of a STATCOM to supply reactive power and dynamically regulate system voltages[19]. Inverter based generation, such as solar photovoltaics and storage, can also provide reactive power if necessary.

**Q17. Please summarize your conclusions.**

**A.** I conclude that i) a transmission alternative to NOPS will address the reliability issues the Company uses to try to justify NOPS and at a considerably lower capital cost, ii) the Company has not given thorough consideration to adding transmission capacity as an alternative to building NOPS, iii) the proposed location for NOPS at the location of the former Michoud generating units has flooded under major storm conditions, damaging the generating units that were located there at the time, iv) under major storm conditions, damage to generation located at NOPS, as well as damage to the distribution system have been correlated with damage to the transmission system, v) if the Company desires more reliability from the transmission alternative, beyond what rebuilding and reinforcing critical transmission lines would provide, a more thorough evaluation would have considered an underground transmission line to provide more reliability for the supply into the Company's service area, and vi) the Company has no

[18] See Exhibit PJL-5, p. 4. Vars, which stands for volt-amperes reactive, is a metric that measures reactive power.

[19] Exhibit PJL-6 is available in its entirety at http://www.sustainablepowersystems.com/wp-content/uploads/2016/03/GTM-Whitepaper-Integrating-High-Levels-of-Renewables-into-Microgrids.pdf

need of black-start capacity to be provided by the proposed NOPS generation, considering current black-start capabilities that are available.

**Q18. Does this conclude your testimony?**

**A.** Yes, at this time.

**AFFIDAVIT**

STATE OF FLORIDA )
)
COUNTY OF LEE )

I, Peter J. Lanzalotta, do hereby swear under the penalty of perjury the following: That I am the person identified in the attached prepared testimony and that such testimony was prepared by me under my direct supervision; that the answers and information set forth therein are true and accurate to the best of my personal knowledge and belief; and that if asked the questions set forth herein, my answers thereto would, under oath, remain the same.

Peter J. Lanzalotta

**SWORN TO AND SUBSCRIBED BEFORE ME THIS 11TH DAY OF OCTOBER, 2017**

T. MATCHETT
Notary Public - State of Florida
Commission # FF 233071
My Comm. Expires Aug 4, 2019
Bonded through National Notary Assn

T. Matchett

THOMAS D. MATCHETT
**NOTARY PUBLIC #FF233071**

My commission expires: 08/04/2019

# Exhibit PJL-1
# Resume of Peter J. Lanzalotta

**Prior Experience of Peter J. Lanzalotta**

Mr. Lanzalotta has more than thirty-five years of experience in electric utility system planning, power pool operations, distribution operations, electric service reliability, load and price forecasting, and market analysis and development. Mr. Lanzalotta has appeared as an expert witness on utility reliability, planning, operation, and rate matters in more than 130 proceedings in 25 states, the District of Columbia, the Provinces of Alberta, Nova Scotia, and Ontario, before the Federal Energy Regulatory Commission, and before U. S. District Court. He has developed evaluations of electric utility system cost, system value, reliability planning, transmission and distribution maintenance practices, and reliability of service.

Prior to his forming Lanzalotta & Associates LLC in 2001, he was a Partner at Whitfield Russell Associates in Washington DC for fifteen years and a Senior Associate for approximately four years before that. He holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration with a concentration in Finance from Loyola College of Baltimore.

Prior to joining Whitfield Russell Associates in 1982, Mr. Lanzalotta was employed by the Connecticut Municipal Electric Energy Cooperative ("CMEEC") as a System Engineer. He was responsible for providing operational, financial, and rate expertise to Coop's budgeting, ratemaking and system planning processes. He participated on behalf of CMEEC in the Hydro-Quebec/New England Power Pool Interconnection project and initiated the development of a database to support CMEEC's pool billing and financial data needs.

Prior to his CMEEC employment, he served as Chief Engineer at the South Norwalk (Connecticut) Electric Works, with responsibility for planning, data processing, engineering, rates and tariffs, generation and bulk power sales, and distribution operations. While at South Norwalk, he conceived and implemented, through Northeast Utilities and NEPOOL, a peak-shaving plan for South Norwalk and a neighboring municipal electric utility, which resulted in substantial power supply savings. He programmed and implemented a computer system to perform customer billing and maintain accounts receivable accounting. He also helped manage a generating station overhaul and the undergrounding of the distribution system in South Norwalk's downtown.

From 1977 to 1979, Mr. Lanzalotta worked as a public utility consultant for Van Scoyoc & Wiskup and separately for Whitman Requart & Associates in a variety of positions. During this time, he developed cost of service, rate base evaluation, and rate design impact data to support direct testimony and exhibits in a variety of utility

proceedings, including utility price squeeze cases, gas pipeline rates, and wholesale electric rate cases.

Prior to that, He worked for approximately 2 years as a Service Tariffs Analyst for the Finance Division of the Baltimore Gas & Electric Company where he developed cost and revenue studies, evaluated alternative rate structures, and studied the rate structures of other utilities for a variety of applications. He was also employed by BG&E in Electric System Operations for approximately 3 years, where his duties included operations analysis, outage reporting, and participation in the development of BG&E's first computerized customer information and service order system.

Mr. Lanzalotta is a member of the Institute of Electrical & Electronic Engineers, the Association of Energy Engineers, the National Fire Protection Association, and the American Solar Energy Society. He is also registered Professional Engineer in the states of Maryland and Connecticut.

# Exhibit PJL-2
# Proceedings in Which Peter J. Lanzalotta Has Testified

**Proceedings in Which**
**Peter J. Lanzalotta**
**Has Testified**

1. **In re: Public Service Company of New Mexico**, Docket Nos. ER78-337 and ER78-338 before the Federal Energy Regulatory Commission, concerning the need for access to calculation methodology underlying filing.

2. **In re: Baltimore Gas and Electric Company**, Case No. 7238-V before the Maryland Public Service Commission, concerning outage replacement power costs.

3. **In re: Houston Lighting & Power Company**, Texas Public Utilities Commission Docket No. 4712, concerning modeling methods to determine rates to be paid to cogenerators and small power producers.

4. **In re: Nevada Power Company**, Nevada Public Service Commission, Docket No. 83-707 concerning rate case fuel inventories, rate base items, and O&M expense.

5. **In re: Virginia Electric & Power Company**, Virginia State Corporation Commission, Case No. PUE820091, concerning the operating and reliability-based need for additional transmission facilities.

6. **In re: Public Service Electric & Gas Company**, New Jersey Board of Public Utilities, Docket No. 831-25, concerning outage replacement power costs.

7. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. P-830453, concerning outage replacement power costs.

8. **In re: Cincinnati Gas & Electric Company**, Public Utilities Commission of Ohio, Case No. 83-33-EL-EFC, concerning the results of an operations/fuel-use audit conducted by Mr. Lanzalotta.

9. **In re: Kansas City Power and Light Company**, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

10. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. R-850152, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

11. **In re: ABC Method Proposed for Application to Public Service Company of Colorado**, before the Public Utilities Commission of the State of Colorado, on behalf of the Federal Executive Agencies ("FEA"), concerning a production cost allocation methodology proposed for use in Colorado.

12. **In re: Duquesne Light Company**, Docket No. R-870651, before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning the system reserve margin needed for reliable service.

13. **In re: Pennsylvania Power Company**, Docket No. I-7970318 before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning outage replacement power costs.

14. **In re: Commonwealth Edison Company**, Docket No. 87-0427 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from new base-load generating facilities, needed for reliable system operation.

15. **In re: Central Illinois Public Service Company**, Docket No. 88-0031 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the degree to which existing generating capacity is needed for reliable and/or economic system operation.

16. **In re: Illinois Power Company**, Docket No. 87-0695 before the State of Illinois Commerce Commission, on behalf of Citizens Utility Board of Illinois, Governors Office of Consumer Services, Office of Public Counsel and Small Business Utility Advocate, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

17. **In re: Florida Power Corporation**, Docket No. 860001-EI-G (Phase II), before the Florida Public Service Commission, on behalf of the Federal Executive Agencies of the United States, concerning an investigation into fuel supply relationships of Florida Power Corporation.

18. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Docket No. 877, on behalf of the Public Service Commission Staff, concerning the need for and availability of new generating facilities.

19. **In re: South Carolina Electric & Gas Company**, before the South Carolina Public Service Commission, Docket No. 88-681-E, On Behalf of the State of Carolina Department of Consumer Affairs, concerning the capacity needed for reliable system operation, the capacity available from existing generating units, relative jurisdictional rate of return, reconnection charges, and the provision of supplementary, backup, and maintenance services for QFs.

20. **In re: Commonwealth Edison Company**, Illinois Commerce Commission, Docket Nos. 87-0169, 87-0427, 88-0189, 88-0219, and 88-0253, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation.

21. **In re: Illinois Power Company**, Illinois Commerce Commission, Docket No. 89-0276, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of capacity available from existing generating units.

22. **In re: Jersey Central Power & Light Company**, New Jersey Board of Public Utilities, Docket No. EE88-121293, on behalf of the State of New Jersey Department of the Public Advocate, concerning evaluation of transmission planning.

23. **In re: Canal Electric Company**, before the Federal Energy Regulatory Commission, Docket No. ER90-245-000, on behalf of the Municipal Light Department of the Town of Belmont, Massachusetts, concerning the reasonableness of Seabrook Unit No. 1 Operating and Maintenance expense.

24. **In re: New Hampshire Electric Cooperative Rate Plan Proposal**, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation.

25. **In re: Connecticut Light & Power Company**, before the Connecticut Department of Public Utility Control, Docket No. 90-04-14, on behalf of a group of Qualifying Facilities concerning O&M expenses payable by the QFs.

26. **In re: Duke Power Company**, before the South Carolina Public Service Commission, Docket No. 91-216-E, on behalf of the State of South Carolina Department of Consumer Advocate, concerning System Planning, Rate Design and Nuclear Decommissioning Fund issues.

27. **In re: Jersey Central Power & Light Company**, before the Federal Energy Regulatory Commission, Docket No. ER91-480-000, on behalf of the Boroughs of Butler, Madison, Lavallette, Pemberton and Seaside Heights, concerning the appropriateness of a separate rate class for a large wholesale customer.

28. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Formal Case No. 912, on behalf of the Staff of the Public Service Commission of the District of Columbia, concerning the Application of PEPCO for an increase in retail rates for the sale of electric energy.

29. **Commonwealth of Pennsylvania, House of Representatives**, General Assembly House Bill No. 2273. Oral testimony before the Committee on Conservation, concerning proposed Electromagnetic Field Exposure Avoidance Act.

30. **In re: Hearings on the 1990 Ontario Hydro Demand\Supply Plan**, before the Ontario Environmental Assessment Board, concerning Ontario Hydro's System Reliability Planning and Transmission Planning.

31. **In re: Maui Electric Company**, Docket No. 7000, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning MECO's generation system, fuel and purchased power expense, depreciation, plant additions and retirements, contributions and advances.

32. **In re: Hawaiian Electric Company, Inc.**, Docket No. 7256, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning need for, design of, and routing of proposed transmission facilities.

33. **In re: Commonwealth Edison Company**, Docket No. 94-0065 before the Illinois Commerce Commission on behalf of the City of Chicago, concerning the capacity needed for system reliability.

34. **In re: Commonwealth Edison Company**, Docket No. 93-0216 before the Illinois Commerce Commission on behalf of the Citizens for Responsible Electric Power, concerning the need for proposed 138 kV transmission and substation facilities.

35. **In re: Commonwealth Edison Company**, Docket No. 92-0221 before the Illinois Commerce Commission on behalf of the Friends of Illinois Prairie Path, concerning the need for proposed 138 kV transmission and substation facilities.

36. **In re: Commonwealth Edison Company**, Docket No. 94-0179 before the Illinois Commerce Commission on behalf of the Friends of Sugar Ridge, concerning the need for proposed 138 kV transmission and substation facilities.

37. **In re: Public Service Company of Colorado**, Docket Nos. 95A-531EG and 95I-464E before the Colorado Public Utilities Commission on behalf of the Office of Consumer Counsel, concerning a proposed merger with Southwestern Public Service Company and a proposed performance-based rate-making plan.

38. **In re: South Carolina Electric & Gas Company, Duke Power Company, and Carolina Power & Light Company**, Docket No. 95-1192-E, before the South Carolina Public Service Commission on behalf of the South Carolina Department of Consumer Advocate, concerning avoided cost rates payable to qualifying facilities.

39. **In re: Lawrence A. Baker v. Truckee Donner Public Utility District**, Case No. 55899, before the Superior Court of the State of California on behalf of Truckee Donner Public Utility District, concerning the reasonableness of electric rates.

40. **In re: Black Hills Power & Light Company**, Docket No. OA96-75-000, before the Federal Energy Regulatory Commission on behalf of the City of Gillette, Wyoming, concerning the Black Hills' proposed open access transmission tariff.

41. **In re: Metropolitan Edison Company and Pennsylvania Electric Company** for Approvals of the Restructuring Plan Under Section 2806, Docket Nos. R-00974008 and R-00974009 before the Pennsylvania PUC on behalf of Operating NUG Group, concerning miscellaneous restructuring issues.

42. **In re: New Jersey State Restructuring Proceeding** for consideration of proposals for retail competition under BPU Docket Nos. EX94120585U; E097070457; E097070460; E097070463; E097070466 before the New Jersey BPU on behalf of the New Jersey Division of Ratepayer Advocate, concerning load balancing, third party settlements, and market power.

43. **In re: Arbitration Proceeding In City of Chicago v. Commonwealth Edison** for consideration of claims that franchise agreement has been breached, Proceeding No. 51Y-114-350-96 before an arbitration panel board on behalf of the City of Chicago concerning electric system reliability.

44. **In re: Transalta Utilities Corporation**, Application No. RE 95081 on behalf of the ACD companies, before the Alberta Energy And Utilities Board in reference to the use and value of interruptible capacity.

45. **In re: Consolidated Edison Company,** Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for a breach of contract to provide firm transmission service on a non-discriminatory basis.

**46.** **In re: ESBI Alberta Ltd.,** Application No. 990005 on behalf of the FIRM Customers, before the Alberta Energy And Utilities Board concerning the reasonableness of the cost of service plus management fee proposed for 1999 and 2000 by the transmission administrator.

**47.** **In re: South Carolina Electric & Gas Company,** Docket No. 2000-0170-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new and repowered generating units at the Urquhart generating station.

**48.** **In re: BGE,** Case No. 8837 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

**49.** **In re: PEPCO,** Case No. 8844 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

**50.** **In re: GenPower Anderson LLC,** Docket No. 2001-78-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service

Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the GenPower Anderson LLC generating station.

**51.** **In re: Pike County Light & Power Company,** Docket No. P-00011872, on behalf of Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Pike County request for a retail rate cap exception.

**52.** **In re: Potomac Electric Power Company and Conectiv,** Case No. 8890, on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning the proposed merger of Potomac Electric Power Company and Conectiv.

**53.** **In re: South Carolina Electric & Gas Company,** Docket No. 2001-420-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the Jasper County generating station.

**54.** **In re: Connecticut Light & Power Company,** Docket No. 217 on behalf of the Towns of Bethel, Redding, Weston, and Wilton, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between Plumtree Substation, Bethel and Norwalk Substation, Norwalk.

**55.** **In re: The City of Vernon, California,** Docket No. EL02-103 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting calendar year 2001 transactions.

**56.** **In re: San Diego Gas & Electric Company et. al.,** Docket No. EL00-95-045 on behalf of the City of Vernon, California before the Federal Energy Regulatory Commission concerning refunds and other monies payable in the California wholesale energy markets.

**57.** **In re: The City of Vernon, California,** Docket No. EL03-31 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2002 transactions.

**58.** **In re: Jersey Central Power & Light Company,** Docket Nos. ER02080506, ER02080507, ER02030173, and EO02070417 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

**59.** **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability rules, standards and indices.

**60.** **In re: Central Maine Power Company,** Docket No. 2002-665, on behalf of the Maine Public Advocate and the Town of York before the Maine Public Utilities Commission concerning a Request for Commission Investigation into the New CMP Transmission Line Proposal for Eliot, Kittery, and York.

**61.** **In re: Metropolitan Edison Company,** Docket No. C-20028394, on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission concerning the reliability service complaint of Robert Lawrence.

**62.** **In re: The California Independent System Operator Corporation,** Docket No. ER00-2019 *et al.* on behalf of the City of Vernon, California, before the Federal Energy Regulatory Commission concerning wholesale transmission tariffs, rates and rate structures proposed by the California ISO.

**63.** **In re: The Narragansett Electric Company,** Docket No. 3564 on behalf of the Rhode Island Department of Attorney General, before the Rhode Island Public Utilities Commission concerning the proposed relocation of the E-183 transmission line.

**64.** **In re: The City of Vernon, California,** Docket No. EL04-34 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2003 transactions.

**65.** **In re: Atlantic City Electric Company,** Docket No. ER03020110 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

**66.** **In re: Connecticut Light & Power Company and the United Illuminating Company,** Docket No. 272 on behalf of the Towns of Bethany, Cheshire, Durham, Easton, Fairfield, Hamden, Middlefield, Milford, North Haven, Norwalk, Orange, Wallingford, Weston, Westport, Wilton, and Woodbridge, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between the Scoville Rock Switching Station in Middletown and the Norwalk Substation in Norwalk, Connecticut.

**67.** **In re: Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company,** Docket No. I-00040102, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning electric service reliability performance.

**68.** **In re: Entergy Louisiana, Inc.**, Docket No. U-20925 RRF-2004 on behalf of Bayou Steel before the Louisiana Public Service Commission concerning a proposed increase in base rates.

**69.** **In re: Jersey Central Power & Light Company,** Docket No. ER02080506, Phase II, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

**70.** **In re: Maine Public Service Company,** Docket No. 2004-538, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 138 kV transmission line from Limestone, Maine to the Canadian border near Hamlin, Maine.

**71.** **In re: Pike County Light and Power Company,** Docket No. M-00991220F0002, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Company's Petition to amend benchmarks for distribution reliability.

**72.** **In re: Atlantic City Electric Company,** Docket No. EE04111374, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning the need for transmission system reinforcement, and related issues.

**73.** **In re: Bangor Hydro-Electric Company,** Docket No. 2004-771, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 345 kV transmission line from Orrington, Maine to the Canadian border near Baileyville, Maine.

**74.** **In re: Eastern Maine Electric Cooperatve,** Docket No. 2005-17, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a petition to approve a purchase of transmission capacity on a 345 kV transmission line from Maine to the Canadian province of New Brunswick.

**75.** **In re: Virginia Electric and Power Company,** Case No. PUE-2005-00018, on behalf of the Town of Leesburg VA and Loudoun County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for transmission and substation facilities in Loudoun County.

**76.** **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability reporting, standards, and indices.

**77.** **In re: Proposed Merger Involving Constellation Energy Group Inc. and the FPL Group, Inc.**, Case No. 9054, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the proposed merger involving Baltimore Gas & Electric Company and Florida Light & Power Company.

**78.** **In re: Proposed Sale and Transfer of Electric Franchise of the Town of St. Michaels to Choptank Electric Cooperative, Inc.,** Case No. 9071, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the sale by St. Michaels of their electric franchise and service area to Choptank.

**79.** **In re: Petition of Rockland Electric Company for the Approval of Changes in Electric Rates, and Other Relief,** BPU Docket No. ER06060483, on behalf of the Department of the Public Advocate, Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning electric service reliability and reliability-related spending.

**80.** **In re: The Complaint of the County of Pike v. Pike County Light & Power Company, Inc.,** Docket No. C-20065942, et al., on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, concerning electric service reliability and interconnecting with the PJM ISO.

**81.** **In re: Application of American Transmission Company to Construct a New Transmission Line,** Docket No. 137-CE-139, on behalf of The Sierra Club of Wisconsin, before the Public Service Commission of Wisconsin, concerning the request to build a new 138 kV transmission line.

**82.** **In re: The Matter of the Self-Complaint of Columbus Southern Power Company and Ohio Power Company Regarding the Implementation of Programs to Enhance Distribution Service Reliability,** Case No. 06-222-EL-SLF, on behalf of The Office of The Ohio Consumers' Counsel, before the Public Utilities Commission of Ohio, concerning distribution system reliability and related topics.

**83.** **In re: Central Maine Power Company,** Docket No. 2006-487, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning CMP's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line between Saco and Old Orchard Beach.

**84.** **In re: Bangor Hydro Electric Company,** Docket No. 2006-686, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning BHE's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line and substation in Hancock County.

**85.** **In re: Commission Staff's Petition For Designation of Competitive Renewable Energy Zones,** Docket No. 33672, on behalf of the Texas Office of Public Utility Counsel, concerning the Staff's Petition and the determination of what areas should be designated as CREZs by the Commission.

**86.** **In re: Virginia Electric and Power Company,** Case No. PUE-2006-00091, on behalf of the Towering Concerns and Stafford County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Stafford County.

**87.** **In re: Trans-Allegheny Interstate Line Company,** Docket Nos. A-110172 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Pennsylvania.

**88.** **In re: Commonwealth Edison Company,** Docket No. 07-0566, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission,

concerning electric transmission and distribution projects promoted as smart grid projects, and the rider proposed to pay for them.

**89.** **In re: Commonwealth Edison Company,** Docket No. 07-0491, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning the applicability of electric service interruption provisions.

**90.** **In re: Hydro One Networks,** Case No. EB-2007-0050, on behalf of Pollution Probe, before the Ontario Energy Board, concerning a request for leave to construct electric transmission facilities in the Province of Ontario.

**91.** **In re: PEPCO Holdings, Inc.,** Docket No. ER-08-686-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

**92.** **In re: PPL Electric Utilities Corporation and Public Service Electric and Gas Company,** Docket No. ER-08-23-000, on behalf of the Joint Consumer Advocates, including the state consumer advocacy offices for the States of Maryland, West Virginia, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

**93.** **In re: PPL Electric Utilities Corporation,** Docket Nos. A-2008-2022941 and P-2008-2038262, on behalf of Springfield Township, Bucks County, PA, before the Pennsylvania Public Utility Commission, concerning the need for and alternatives to proposed electric transmission lines and a proposed electric substation.

**94.** **In re: PEPCO Holdings, Inc.,** Docket No. ER08-1423-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

**95.** **In re: Public Service Electric and Gas Company, Inc.,** Docket No. ER09-249-000, on behalf of the New Jersey Division of Rate Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

**96.** **In re: New York Regional Interconnect Inc.,** Case No. 06-T-0650, on behalf of the Citizens Against Regional Interconnect, before the New York Public Service Commission, concerning the economics of and alternatives to proposed transmission facilities.

**97.** **In re: Central Maine Power Company and Public Service of New Hampshire,** Docket No. 2008-255, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning CMP's and PSNH's Petition for Finding of Public Convenience & Necessity to build the Maine Power Reliability Project, a series of new and rebuilt electric transmission facilities to operate at 345 kV and 115 kV in Maine and New Hampshire.

**98.** **In re: PPL Electric Utilities Corporation, Docket No. A-2009-2082652 et al,** on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning the Company's application for approval to site and construct electric transmission facilities in Pennsylvania.

**99.** **In re: Bangor Hydro-Electric,** Docket No. 2009-26, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning BHE's Petition for Certificate of Public Convenience & Necessity to build a 115 kV transmission line in Washington and Hancock Counties.

**100.** **In re: United States, et al. v. Cinergy Corp., et al.** Civil Action No. IP99-1693 C-M/S, on behalf of Plaintiff United States and Plaintiff-Intervenors State of New York, State of New Jersey, State of Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, before the United States District Court for the Southern District of Indiana, concerning the system reliability impacts of the potential retirement of Gallagher Power Station Unit 1 and Unit 3.

**101.** **In re: Application of Potomac Electric Power Company, et al.** Case No. 9179, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the application for a determination of need under a certificate of public convenience and necessity for the Maryland portion of the MAPP transmission line, and related facilities.

**102.** **In re: Potomac Electric Power Company v. Perini/Tompkins Joint Venture,** Case No. 9210, on behalf of Perini Tompkins before the Maryland Public Service Commission concerning a review of PEPCO's estimates of electric consumption by Perini Tompkins Joint Venture's temporary electric service at National Harbor during a 29 month period for which no metered consumption data is available.

**103.** **In re: Duke Energy Ohio, Inc.,** Case No. 10-503-EL-FOR, on behalf of the Natural Resources Defense Council and Sierra Club before the Public Utilities Commission Of Ohio, concerning a review of the reliability impacts that would

result from closure of selected generating units as part of a review of Duke's 2010 Electric Long-Term Forecast Report and Resources Plan.

**104.** **In re: Detroit Edison Company,** Case Nos. U-16472 and 16489, on behalf of the Michigan Environmental Council and the Natural Resources Defense Council, before the Michigan Public Service Commission, concerning a review looking for studies of the reliability impacts that would result from closure of selected generating units as part of an electric rate increase case.

**105.** **In re: Potomac Electric Power Company,** Case No. 9240, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability performance.

**106.** **In re: ISO New England, Inc.,** Docket No. ER12-991-000, on behalf of the Conservation Law Foundation, before the Federal Energy Regulatory Commission, concerning proposals for procedures for obtaining temporary regulations addressing emissions from electric generating facilities.

**107.** **In re: Western Massachusetts Electric Company, Docket No. D.P.U. 11-119-C** on behalf of the Attorney General of the Commonwealth of Massachusetts, before the Massachusetts Department of Public Utilities, concerning storm preparation, performance, and restoration of electric service.

**108.** **In re: Delmarva Power & Light Company,** Case No. 9285, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.

**109.** **In re: Potomac Electric Power Company,** Case No. 9286, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.

**110.** **In re: Fitchburg Gas And Electric Company,** Civil Action No. 09-00023, on behalf of Marcia D. Bellerman, et al., before the Commonwealth of Massachusetts Superior Court, concerning company and electric system preparedness and execution in dealing with a major winter storm.

**111.** **In re: Duke Energy Indiana, Inc.,** Cause No. 44217, on behalf of Citizens Action Coalition of Indiana, Sierra Club, Save The Valley, and Valley Watch, before the Indiana Utility Regulatory Commission, concerning the role of transmission planning studies as part of the process of deciding whether to

retire coal-fired generation or equip such generation with environmental retrofits.

**112.** **In re: Indianapolis Power & Light Company,** Cause No. 44242, on behalf of Citizens Action Coalition of Indiana and the Sierra Club, before the Indiana Utility Regulatory Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

**113.** **In re: Consumers Energy Company,** Case No. U-17087, on behalf of Michigan Environmental Council and Natural Resources Defense Council, before the Michigan Public Service Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

**114.** **In re: Potomac Electric Power Company,** Case No. 9311, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters and tree trimming expenses as part of a base rate increase case.

**115.** **In re: Jersey Central Power & Light Company,** BPU Docket No. ER12111052, on behalf of the New Jersey Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning reliability issues and storm performance involved in the approval of an increase in base tariff rates.

**116.** **In re: Delmarva Power & Light Company,** Case No. 9317, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters as part of a base rate increase case.

**117.** **In re: PPL Electric Utilities Corporation,** Docket Nos. A-2012-2340872 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning the need for and alternatives to proposed electric transmission lines and proposed electric substations as part of the Northeast Pocono Reliability Project.

**118.** **In re: Baltimore Gas & Electric Co.,** Case No. 9326, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters as part of a base rate increase case.

**119.** **In re: Jersey Central Power & Light Company,** BPU Docket Nos. EO13050391 and AX13030196, on behalf of the New Jersey Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning the prudency of costs incurred in response to major storms.

**120.** **In re: Potomac Electric Power Company,** Case No. 9336, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters as part of a base rate increase case.

**121.** **In re: Baltimore Gas & Electric Co.,** Case No. 9355, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters as part of a base rate increase case.

**122.** **In re: American Transmission Company LLC and Northern States Power Company – Wisconsin,** Docket No. 5-CE-142, on behalf of Citizens Energy Task Force, Inc. and Save Our Unique Lands of Wisconsin, Inc., before the Public Service Commission of Wisconsin, concerning the need for and the benefits expected from proposed transmission facilities.

**123.** **In re: Potomac-Appalachian Transmission Highline, LLC and PJM Interconnection, LLC,** Docket Nos. ER09-1256-002 and ER12-2708-003, on behalf of Intervenors' State Agencies, including the Virginia Office Of The Attorney General's Division Of Consumer Counsel, the Delaware Division Of The Public Advocate, the Maryland Office Of People's Counsel, the Maryland Public Service Commission, the Delaware Public Service Commission, and the Pennsylvania Office Of Consumer Advocate, before the Federal Energy Regulatory Commission, concerning transmission line abandonment costs.

**124.** **In re: The Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.,** Case No. 9361, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a proposed merger case.

**125.** **In re: the Matter of the Application of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for an Electric Security Plan,** Case No. 14-1297-EL-SSO, on behalf of the Sierra Club, before the Public Utilities Commission Of Ohio, concerning electric system reliability and transmission matters.

**126.** **In re: Delmarva Power & Light Company,** Case No. 9393, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning an application for a CPCN for a new 138 kV electric transmission line.

**127.** **In re: The Baltimore Gas & Electric Company,** Case No. 9406, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

**128.** **In re: The Potomac Electric Power Company,** Case No. 9418, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

**129.** **In re: The Matter Of Nova Scotia Power Performance Standards,** Case No. M07387, on behalf of the Nova Scotia Consumer Advocate, before the Nova Scotia Utility and Review Board, concerning electric service reliability-related performance standards.

**130.** **In re: the Matter of the Application of the Ohio Power Company,** Case No. 13-1939-EL-RDR, on behalf of the Ohio Consumers' Counsel, before the Public Utilities Commission Of Ohio, concerning Phase 2 of its gridSMART Project and its gridSMART Phase 2 Rider.

**131.** **In re: PECO Energy Company,** Docket No. P-2016-2546452 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a proposed microgrid pilot plan and recovery of its costs.

**132.** **In re: The Delmarva Power & Light Company,** Case No. 9424, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

**133.** **In re: Jersey Central Power & Light Company,** BPU Docket No. EO16080750, on behalf of the New Jersey Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning a determination that a proposed transmission line in Monmouth County NJ is necessary for the service, convenience, and welfare of the public.

**134.** **In re: Virginia Electric and Power Company,** SCC Case No. PUE-2016-00021, on behalf of Lancaster County, Virginia, before the Virginia State Corporation Commission, concerning the need for rebuilding an existing electric transmission line across the Rappahannock River and the desirability of placing such rebuilt transmission line underground.

**135.** **In re: Virginia Electric and Power Company,** SCC Case No. PUR-2017-00002, on behalf of Fairfax County, Virginia, before the Virginia State Corporation Commission, concerning the need for rebuilding an existing electric substation and the desirability of transmission lines in the vicinity being placed underground.

**136.** **In re: The Potomac Electric Power Company,** Case No. 9443, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

# Exhibit PJL-3
# Company's Response to AAE 8-19

ENTERGY NEW ORLEANS, INC.
CITY OF NEW ORLEANS
Docket No. UD-16-02

Response of: Entergy New Orleans, Inc.
to the Eighth Set of Data Requests
of Requesting Party: Alliance for Affordable
Energy

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Question No.: AAE 8-19 Part No.: Addendum:

Question:

Regarding the transmission options that could replace the need for the 226 MW OPS, provide any analyses on the undergrounding of those facilities or the undergrounding of existing transmission facilities to increase reliability.

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Response:

Without performing a detailed scoping analysis, it is unknown to what extent existing underground construction for the referenced transmission facilities would be feasible or possible. However, it is well known that the expected incremental cost of restoration of overhead transmission facilities does not justify the cost of underground transmission construction and nor does the cost of underground conversion of overhead to underground transmission conversion justify the benefits received from doing so. As an example, Quanta services performed an analysis quantifying the cost of underground transmission within 50 miles of the Texas coast and found that underground transmission construction to be infeasible. A relevant excerpt of this report is provided as an attachment to this response.

close to true), underground conversion is not even close to being cost-effective. These results are similar to other analyses that have been done in other states.

Underground conversion can actually be detrimental in areas subject to storm surge damage. Overhead distribution facilities are generally much faster to repair compared to underground equipment that has been flooded, eroded away, or otherwise damaged by storm surges.

Undergrounding of new facilities is potentially cost-effective, provided the location is not subject to storm surge, depending upon the cost differential of overhead construction versus underground. A typical distribution structure costs about $4000 to replace during hurricane restoration. The failure rate of poles can be approximated by the following equation:

Wood Pole Failure Rate = 0.0001 x exp(0.0421 x W)

W is sustained wind speed in miles per hour.

This equation is explained in the report *Undergrounding Assessment Phase 3 Final Report: Ex Ante Cost and Benefit Modeling*, submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI.

Using these assumptions, the cost per year in restoration costs can be computed for each of the hurricane prone areas. This analysis is shown in Table 5-6. The highest annual expected restoration cost is $1.69 for the Corpus Christi area. Assuming a wood pole life of 60 years and a discount rate of 10%, this amounts to a present value of about $16.85. With 40 distribution poles per mile, this amounts to $674 per mile. Therefore, installing new facilities underground is worthwhile if the incremental cost per mile is less than $674 per mile. This amount will vary based on region and distribution span length, but in any case will be small as a percentage of total construction cost since typical new overhead distribution facilities cost between $100,000 and $200,000 to construct.

Greater societal benefits will not result from hardening of new facilities since the percentage of hardened facilities is small and total storm restoration time is not likely to be affected.

Although the undergrounding of new distribution may not be justified purely on reduced hurricane damage, underground may be desirable for other reasons. If the primary issue is hurricane damage, hardening the overhead design may be more cost-effective. For example, a Class 1pole is 50% stronger than a Class 5 pole, but typically only costs about $200 more. At 40 poles per mile, this amounts to $8000 per mile for a much stronger system. Because of these economics, some utilities in hurricane-prone areas design their distribution systems to Grade B construction rather than Grade C.

**Table 5-6.** Annual restoration cost of wood distribution poles.

| | Hurricane Category | | | | | |
|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | |
| | Annual Probability of Occurrence | | | | | |
| Beaumont-Port Arthur | 4.45% | 1.18% | 0.38% | 0.11% | 0.01% | |
| Brownsville-Harlingen | 1.61% | 0.30% | 0.08% | 0.01% | 0.01% | |
| Corpus Christi | 4.34% | 1.09% | 0.42% | 0.09% | 0.07% | |
| Houston-Sugar Land-Baytown | 3.54% | 0.83% | 0.17% | 0.03% | 0.00% | |
| Victoria | 3.87% | 0.75% | 0.37% | 0.03% | 0.00% | |
| Sustained wind speed (mph) | 84.5 | 103 | 120.5 | 143 | 168 | |
| Failure rate | 0.35% | 0.76% | 1.60% | 4.12% | 11.79% | |
| | Annual Restoration Cost ($/yr)* | | | | | Total ($/yr) |
| Beaumont-Port Arthur | 0.62 | 0.36 | 0.24 | 0.18 | 0.05 | 1.46 |
| Brownsville-Harlingen | 0.23 | 0.09 | 0.05 | 0.02 | 0.05 | 0.43 |
| Corpus Christi | 0.61 | 0.33 | 0.27 | 0.15 | 0.33 | 1.69 |
| Houston-Sugar Land-Baytown | 0.50 | 0.25 | 0.11 | 0.05 | 0.00 | 0.91 |
| Victoria | 0.54 | 0.23 | 0.24 | 0.05 | 0.00 | 1.06 |

* -Annual restoration cost is equal to the restoration cost per structure ($4,000) multiplied by the failure rate multiplied by the probability of occurrence. For example, the annual restoration cost in Beaumont-Port Arthur due to Category 1 hurricanes is $4,000 x 0.35% x 4.45% = $0.62 per year.

In terms of total conversion, there are 28,263 miles of overhead distribution within 50-miles of the Texas coast. At $1 million per mile, total overhead to underground conversion is estimated to cost $28 billion. Assuming that 70% of hurricane damage is eliminated (80% is due to distribution), annual reductions in utility restoration costs are $126 million and annual societal benefits are $85.4 million.

## 5.6 Underground Transmission

Underground transmission is extremely expensive. New underground transmission is roughly ten times the cost of overhead, and presents other technical challenges due to the high phase-to-ground capacitance. Hardening existing transmission structures has already been examined in Section 5.3, and has been shown to not be cost-effective. New transmission is already required to be built to NESC extreme wind criteria. Therefore, any incremental benefit in moving from an extreme-wind-rated overhead transmission design to underground will be minimal, although the additional cost will be substantial.

Using the hardened transmission failure rate assumptions represented in Figure 5-5, the cost per year in restoration costs can be computed for each of the hurricane-prone areas. This analysis is shown in Table 5-7. The highest annual expected restoration cost is $25.18 for the Corpus Christi area. Assuming a transmission structure life of 60 years and a discount rate of 10%, this amounts to a present value of about $251. With 10 transmission structures per mile, this amounts to $2510 per mile. Therefore, installing new transmission facilities underground is worthwhile if the incremental cost per mile is less than $2510 per mile. This amount will vary based on region and transmission span length, but in any case will be small as a percentage of total construction cost since typical new overhead transmission facilities cost $1 million per mile or more.

**Table 5-7.** Annual restoration cost of wood transmission poles.

| | Hurricane Category | | | | | |
|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | |
| | Annual Probability of Occurrence | | | | | |
| Beaumont-Port Arthur | 4.45% | 1.18% | 0.38% | 0.11% | 0.01% | |
| Brownsville-Harlingen | 1.61% | 0.30% | 0.08% | 0.01% | 0.01% | |
| Corpus Christi | 4.34% | 1.09% | 0.42% | 0.09% | 0.07% | |
| Houston-Sugar Land-Baytown | 3.54% | 0.83% | 0.17% | 0.03% | 0.00% | |
| Victoria | 3.87% | 0.75% | 0.37% | 0.03% | 0.00% | |
| Sustained wind speed (mph) | 84.5 | 103 | 120.5 | 143 | 168 | |
| Failure rate | 0.12% | 0.13% | 0.77% | 8.74% | 34.64% | |
| | Annual Restoration Cost ($/yr) | | | | | Total ($/yr) |
| Beaumont-Port Arthur | 3.20 | 0.92 | 1.76 | 5.77 | 2.08 | 13.73 |
| Brownsville-Harlingen | 1.16 | 0.23 | 0.37 | 0.52 | 2.08 | 4.37 |
| Corpus Christi | 3.12 | 0.85 | 1.94 | 4.72 | 14.55 | 25.18 |
| Houston-Sugar Land-Baytown | 2.55 | 0.65 | 0.79 | 1.57 | 0.00 | 5.55 |
| Victoria | 2.79 | 0.59 | 1.71 | 1.57 | 0.00 | 6.65 |

* -Annual restoration cost is equal to the restoration cost per structure ($60,000) multiplied by the failure rate multiplied by the probability of occurrence. For example, the annual restoration cost in Beaumont-Port Arthur due to Category 1 hurricanes is $60,000 x 0.12% x 4.45% = $3.20 per year.

Like the case for distribution, greater societal benefits will not result from hardening of new facilities since the percentage of hardened facilities is small and total storm restoration time is not likely to be affected.

In terms of total conversion, there are 6,577 miles of overhead transmission within 50-miles of the Texas coast. At $5 million per mile, total overhead to underground conversion is estimated to cost $33 billion. Assuming that 15% of hurricane damage is eliminated (20% is due to transmission), annual reductions in utility restoration costs are $27 million and annual societal benefits are $18.3 million.

# Exhibit PJL-4
# NERC Transmission System Planning Performance Requirements
# Standard TPL-001-4

## A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   **4.1. Functional Entity**

   **4.1.1.** Planning Coordinator.

   **4.1.2.** Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

## B. Requirements

**R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

**1.1.** System models shall represent:

**1.1.1.** Existing Facilities

**1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

**1.1.3.** New planned Facilities and changes to existing Facilities

**1.1.4.** Real and reactive Load forecasts

**1.1.5.** Known commitments for Firm Transmission Service and Interchange

**1.1.6.** Resources (supply or demand side) required for Load

**R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

**2.1.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

**2.1.1.** System peak Load for either Year One or year two, and for year five.

**2.1.2.** System Off-Peak Load for one of the five years.

**2.1.3.** P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

**2.1.4.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

**2.1.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

**2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

**2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

**2.3.** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

**2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

**2.4.1.** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

**2.4.2.** System Off-Peak Load for one of the five years.

**2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

**2.5.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

**2.6.** Past studies may be used to support the Planning Assessment if they meet the following requirements:

**2.6.1.** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

**2.6.2.** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

**2.7.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

**2.7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

**2.7.2.** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

**2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

**2.7.4.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

**2.8.** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

**2.8.1.** List System deficiencies and the associated actions needed to achieve required System performance.

**2.8.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

**R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**3.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

**3.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

**3.3.** Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

**3.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

**3.3.1.1.** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

**3.3.1.2.** Tripping of Transmission elements where relay loadability limits are exceeded.

**3.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

**3.4.** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies

to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

**3.4.1.** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

**3.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

**R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**4.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

**4.1.1.** For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

**4.1.2.** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

**4.1.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

**4.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

**4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

**4.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

**4.3.1.1.** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

**4.3.1.2.** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

**4.3.1.3.** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

**4.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

**4.4.** Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

**4.4.1.** Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

**4.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

**R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**R7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

**R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

## Table 1 – Steady State & Stability Performance Planning Events

**Steady State & Stability:**

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

**Steady State Only:**

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

**Stability Only:**

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

| Category | Initial Condition | Event [1] | Fault Type [2] | BES Level [3] | Interruption of Firm Transmission Service Allowed [4] | Non-Consequential Load Loss Allowed |
|---|---|---|---|---|---|---|
| **P0**<br>No Contingency | Normal System | None | N/A | EHV, HV | No | No |
| **P1**<br>Single Contingency | Normal System | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer [5]<br>4. Shunt Device [6] | 3Ø | EHV, HV | No[9] | No[12] |
| | | 5. Single Pole of a DC line | SLG | | | |
| **P2**<br>Single Contingency | Normal System | 1. Opening of a line section w/o a fault [7] | N/A | EHV, HV | No[9] | No[12] |
| | | 2. Bus Section Fault | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| | | 3. Internal Breaker Fault [8] (non-Bus-tie Breaker) | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| | | 4. Internal Breaker Fault (Bus-tie Breaker) [8] | SLG | EHV, HV | Yes | Yes |

| Category | Initial Condition | Event [1] | Fault Type [2] | BES Level [3] | Interruption of Firm Transmission Service Allowed [4] | Non-Consequential Load Loss Allowed |
|---|---|---|---|---|---|---|
| **P3**<br>Multiple Contingency | Loss of generator unit followed by System adjustments[9] | Loss of one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer [5]<br>4. Shunt Device [6] | 3Ø | EHV, HV | No[9] | No[12] |
| | | 5. Single pole of a DC line | SLG | | | |
| **P4**<br>Multiple Contingency<br>*(Fault plus stuck breaker[10])* | Normal System | Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer [5]<br>4. Shunt Device [6]<br>5. Bus Section | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| | | 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus | SLG | EHV, HV | Yes | Yes |
| **P5**<br>Multiple Contingency<br>*(Fault plus relay failure to operate)* | Normal System | Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer [5]<br>4. Shunt Device [6]<br>5. Bus Section | SLG | EHV | No[9] | No |
| | | | | HV | Yes | Yes |
| **P6**<br>Multiple Contingency<br>*(Two overlapping singles)* | Loss of one of the following followed by System adjustments.[9]<br>1. Transmission Circuit<br>2. Transformer [5]<br>3. Shunt Device[6]<br>4. Single pole of a DC line | Loss of one of the following:<br>1. Transmission Circuit<br>2. Transformer [5]<br>3. Shunt Device [6] | 3Ø | EHV, HV | Yes | Yes |
| | | 4. Single pole of a DC line | SLG | EHV, HV | Yes | Yes |

| Category | Initial Condition | Event [1] | Fault Type [2] | BES Level [3] | Interruption of Firm Transmission Service Allowed [4] | Non-Consequential Load Loss Allowed |
|---|---|---|---|---|---|---|
| **P7**<br>Multiple Contingency<br>*(Common Structure)* | Normal System | The loss of:<br>1. Any two adjacent (vertically or horizontally) circuits on common structure [11]<br>2. Loss of a bipolar DC line | SLG | EHV, HV | Yes | Yes |

**Table 1 – Steady State & Stability Performance Extreme Events**

**Steady State & Stability**

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

**Steady State**

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

**Stability**

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

| Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events) |
|---|
| 1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. |
| 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. |
| 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. |
| 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. |
| 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. |
| 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. |
| 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. |
| 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. |
| 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. |
| 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. |
| 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. |
| 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. |
| 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & |

| Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events) |
| --- |
| 67), and tripping (#86, & 94). |

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

## III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

## C. Measures

**M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

**M2.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

**M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

**M4.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

**M5.** Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

**M6.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

**M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

**M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1 Compliance Enforcement Authority

Regional Entity

#### 1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

### 1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

### 1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

### 1.5 Additional Compliance Information

None

## 2. Violation Severity Levels

| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1** | The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6. | The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6. | The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6. | The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6.<br>OR<br>The responsible entity's System model did not represent projected System conditions as described in Requirement R1.<br>OR<br>The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan. |
| **R2** | The responsible entity failed to comply with Requirement R2, Part 2.6. | The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8. | The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7. | The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7.<br>OR<br>The responsible entity does not have a completed annual Planning Assessment. |
| **R3** | The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5. | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in | The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. |

| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | OR<br>The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events. | Table 1.<br>OR<br>The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3. | OR<br>The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.<br>OR<br>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1. |
| **R4** | The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5. | The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1.<br>OR<br>The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events. | The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1.<br>OR<br>The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3. | The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.<br>OR<br>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1. |
| **R5** | N/A | N/A | N/A | The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System. |
| **R6** | N/A | N/A | N/A | The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6. |

| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R7** | N/A | N/A | N/A | The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies. |
| **R8** | The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.<br>OR,<br>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request. | The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.<br>OR,<br>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request. | The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.<br>OR,<br>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request. | The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.<br>OR<br>The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.<br>OR<br>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.<br>OR<br>The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing. |

## E. Regional Variances

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| 0 | February 8, 2005 | BOT Approval | Revised |
| 0 | June 3, 2005 | Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2 | Errata |
| 0 | July 24, 2007 | Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2. | Errata |
| 0.1 | October 29, 2008 | BOT adopted errata changes; updated version number to "0.1" | Errata |
| 0.1 | May 13, 2009 | FERC Approved – Updated Effective Date and Footer | Revised |
| 1 | Approved by Board of Trustees February 17, 2011 | Revised footnote 'b' pursuant to FERC Order RM06-16-009 | Revised (Project 2010-11) |
| 2 | August 4, 2011 | Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0. | Project 2006-02 – complete revision |
| 2 | August 4, 2011 | Adopted by Board of Trustees | |
| 1 | April 19, 2012 | FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693. | |
| 3 | February 7, 2013 | Adopted by the NERC Board of Trustees.<br>TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0. | |
| 4 | February 7, 2013 | Adopted by the NERC Board of Trustees.<br>TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies. | |
| 4 | October 17, 2013 | FERC Order issued approving TPL-001-4 (Order effective December 23, 2013). | |
| 4 | May 7, 2014 | NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High. | Revision |
| 4 | November 26, 2014 | FERC issued a letter order approving change to VRF in | |

| | | | |
|---|---|---|---|
| | | Requirement 1 from Medium to High. | |

# Exhibit PJL-5
# Description of an Static Var Compensator


# SVC
# Static Var Compensator
# An insurance for improved grid system stability and reliability

Power and productivity
for a better world™

# It's not the power in that counts...
# ...it's the power that comes out!

## Increased efficiency in power systems

Demand is rising all the time and modern society would cease to function without access to electricity. As the volume of power transmitted and distributed increases, so do the requirements for high quality and reliable supply.

At the same time, rising costs and growing environmental concerns make the process of building new power transmission and distribution lines increasingly complicated and time-consuming. Making existing lines as well as new ones more efficient and economical, then becomes a compelling alternative.

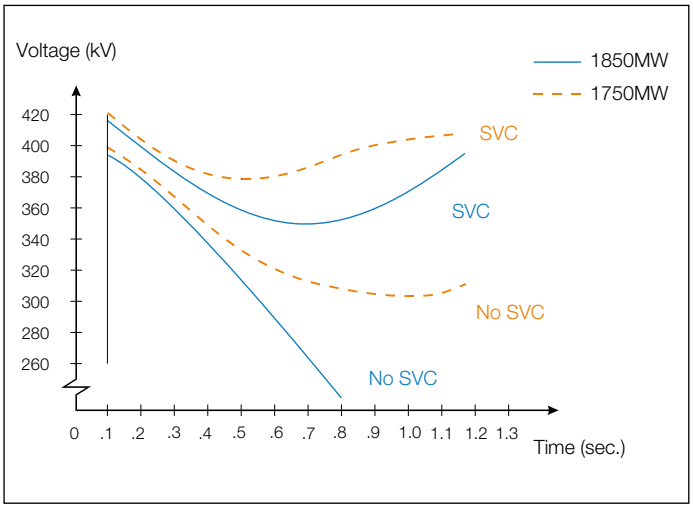
### Major savings at reasonable cost

Optimum power transmission and distribution also entails the reduction of transfer losses and provision of adequate power quality and availability at the receiving end.

The SVC is a solid-state reactive power compensation device based on high power thyristor technology.

An SVC can improve power system transmission and distribution performance in a number of ways. Installing an SVC at one or more suitable points in the network can increase transfer capability and reduce losses while maintaining a smooth voltage profile under different network conditions. The dynamic stability of the grid can also be improved, and active power oscillations mitigated.

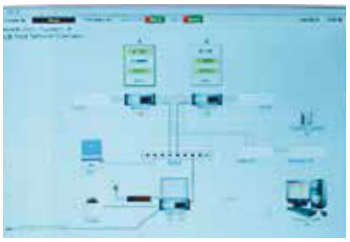
By developing efficient semiconductors (thyristors) dimensioned for high power ratings, ABB has created the perfect environment for reactive power compensation. This technology has also proved highly effective in HVDC applications and thyristor drives for industry.



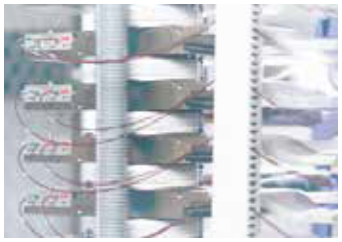

**These voltages demonstrate post fault stabilizing effect of an SVC.**

**Power Transformer**

## The ABB static var compensator includes the following major components:



**Control System**



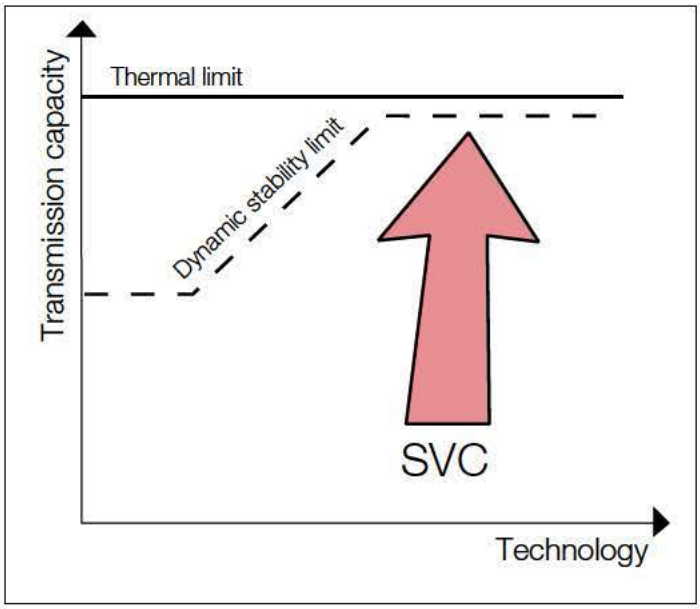
**Thyristor Valves**

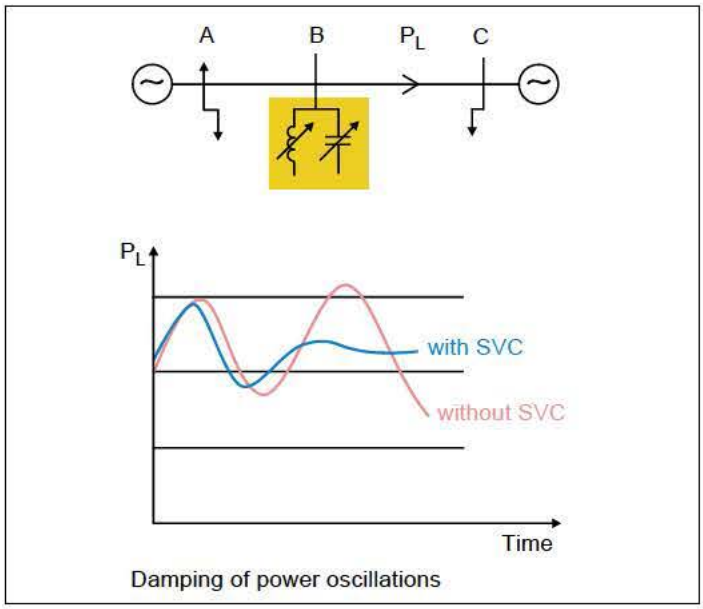
**Capacitor Banks**

**Reactors**

To obtain overall control of the reactive power in a network, thyristor controlled reactors and thyristor switched capacitors are often combined with mechanically switched shunt reactors and capacitors, controlled by the SVC.

# An SVC can considerably improve grid reliability and availability




Damping of power oscillations

The global trend is towards ever larger power networks, longer transmission lines, and higher consumption. Energy is also becoming increasingly expensive. To cope, power transmission and distribution systems have to become more efficient.

In installations all around the world, ABB SVC technology has done exactly this. It has proved second to none in increasing power transmission and distribution capacity at a lower cost.

**The benefits of SVC to power transmission:**

- Stabilized voltages in weak systems
- Reduced transmission losses
- Increased transmission capacity, to reduce, defer or eliminate the need for new lines
- Higher transient stability limit
- Increased damping of minor disturbances
- Greater voltage control and stability
- Power oscillation damping

Systems interconnected via a relatively weak link often experience power oscillation problems. Transmission capability is then determined by damping. By increasing the damping factor (typically by 1-2 MW per Mvar installed) an SVC can eliminate or postpone the need to install new lines.

In other cases, transient (angular) stability will be a limiting factor on power transmission capacity. SVC will often help to mitigate such situations, as well.

**The benefits of SVC to power distribution:**

- Stabilized voltage at the receiving end of long lines
- Increased productivity as stabilized voltage means better utilized capacity
- Reduced reactive power consumption, which gives lower losses and improved tariffs
- Balanced asymmetrical loads reduce system losses and enable lower stresses in rotating machinery
- Enables better use of equipment (particularly transformers and cables)
- Reduced voltage fluctuations and light flicker
- Decreased harmonic distortion

**The SVC is an excellent tool for achieving dynamic voltage control of power systems.**

# Voltage stabilisation

SVC is the preferred tool for dynamic reactive power support in high voltage transmission grids. Thanks to its inherent capability for high-speed, cycle-by-cycle control of vars, it will counteract the often hazardous voltage depressions that follow in conjunction with faults in the grid. These highly dynamic events, where the ever increasing use of induction motors (like those in air-conditioning units and wind power turbine-generators) stresses the grid, will need an SVC to maintain the grid voltage and safeguard the fault ride-through capability.

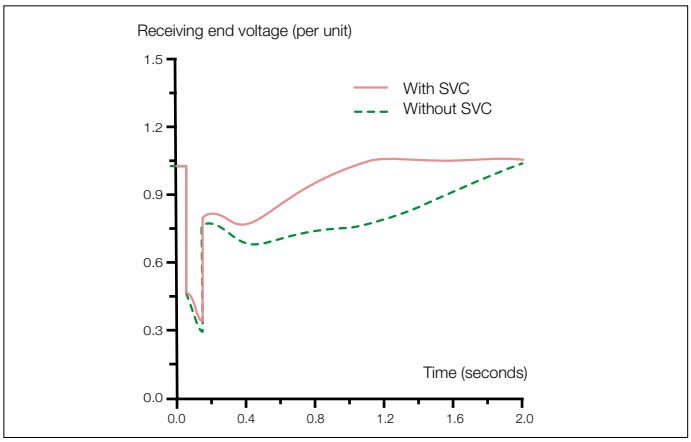
Additionally, if the SVC includes var absorbtion capability, it will effectively suppress temporary overvoltages that may appear upon fault clearing. The SVC will make sure the grid voltage always stays within acceptable limits. In steady-state it will also assist the operators with accurate voltage control so that the voltage profile of the grid is optimized.

## Boosting transmission capacity

The SVC will ensure that the system voltage does not sag even when the power flow grows heavy. This means that more power can be transmitted  through the system under stable conditions over existing lines.

An ABB SVC can boost transmission capacity by tens of percent in most cases. Optimum improvement is sometimes achieved in combination with series compensation.

**Post fault voltage recoveries with and without SVC.**




**This SVC has boosted power transmission capacity by over 50 percent in a 230 kV system.**

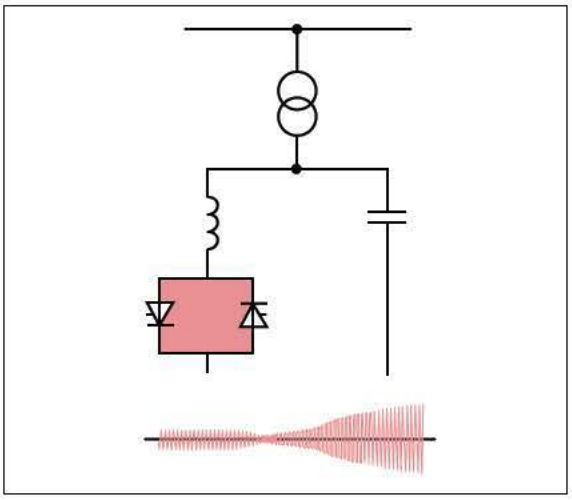
**SVC for voltage stabilisation of a large pulsating load.**

# Basic SVC schemes

### Thyristor controlled reactor and fixed capacitor, TCR/FC

A reactor and thyristor valve are incorporated in each single-phase branch. Power is changed by controlling the current through the reactor via the thyristor valve. The on-state interval is controlled by delaying triggering of the thyristor valve relative to the natural zero current crossing.

A thyristor controlled reactor (TCR) is used in combination with a fixed capacitor (FC) when reactive power generation or alternatively, absorption and generation is required. This is often the optimum solution for sub-transmission and distribution.



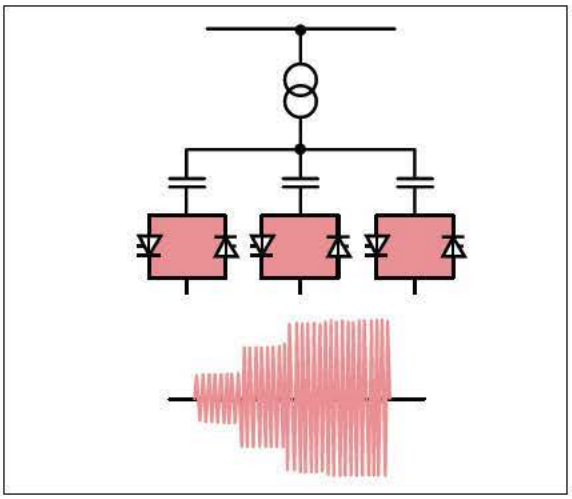
### TCR/FCs are characterized by

- Continuous control
- No transients
- Elimination of harmonics by tuning the FCs as filters
- Compact design

### Thyristor switched capacitor, TSC

A shunt capacitor bank is divided into an appropriate number of branches. Each branch is individually switched on or off via a thyristor valve. Switching takes place when the voltage across the thyristor valve is zero, making it virtually transient-free.

Disconnection is effected by suppressing the firing pulses to the thyristors which will be blocked when the current reaches zero.



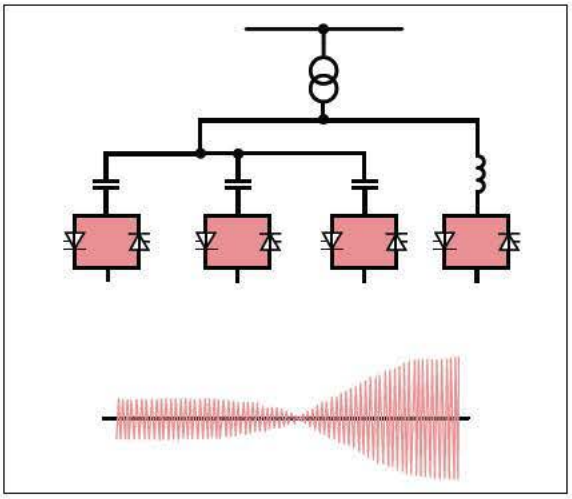
### TSCs are characterized by

- Stepped control
- No transients
- No harmonics
- Low losses
- Redundancy and flexibility

### Thyristor controlled reactor/Thyristor switched capacitor, TCR/TSC

A combined TCR and TSC is the optimum solution in many cases. With a TCR/TSC compensator, continuously variable reactive power is obtained across the entire control range plus full control of both the inductive and the capacitive parts of the compensator.

The principal benefit is optimum performance during major disturbances in the power system, such as line faults and load rejections.



### TCR/TSC combinations are characterized by

- Continuous control
- No transients
- Elimination of harmonics via filters or TSR (thyristor switched reactor) control
- Low losses
- Redundancy
- Flexible control and operation

# Control and protection: MACH

ABB's SVC controls are based on a high performance platform called MACH. The platform is used throughout FACTS and HVDC applications, and thus becomes a well-known associate to the power transmission industry. The platform is based on standardized hardware, Windows-applications, a user-friendly high-level functional programming tool and open interfaces. MACH is built to be recognized with ease.

The SVC performance requirements are high as sub-cycle action is often needed. MACH uses an industrial PC equipped with state-of the-art signal processors, powerful enough to ensure accurate switching of the SVC thyristors, even for the most demanding applications. Processor capacity can easily be expanded, and similarly the set of input and output circuitry can be adapted in order to be compatible with local conditions. ABB's vast FACTS experience is behind every application program that is tailored for customers worldwide.

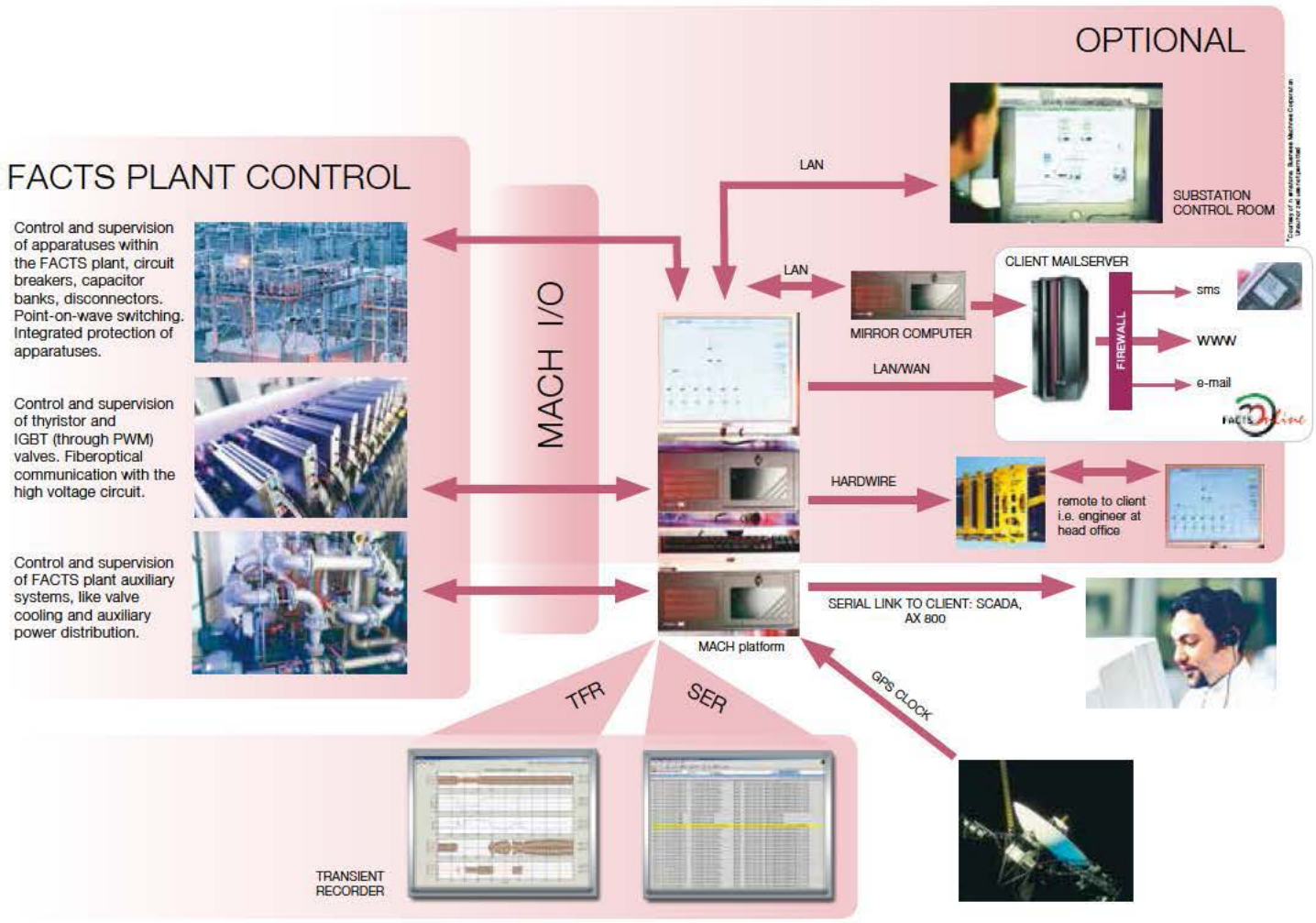
**Field proven controls include:**

- symmetrical as well as negative-phase sequence voltage control
- adaptive gain control [1)]
- transient voltage control strategies [2)]
- power oscillation damping algorithms
- coordinated control of other reactive power elements (Mechanically switched capacitors and reactors (MSC, MSR))
- SVC self-test modes

The MACH concept is built with open interfaces. This elegantly enables remote control and interrogation to be implemented. ABB has developed an internet-based concept for remote control and supervision of FACTS installations, we call it FACTS ON-LINE. This way we are never far away.

[1)] To optimize control speed and stability at varying grid strengths

[2)] Including active voltage support during system faults and mitigation of possible overvoltages at fault clearing




The FACTS control applications within MACH are supported by a Human Machine Interface (HMI). The HMI uses the hardware platform (dedicated industrial PC), into which user friendly databases and information applications are programmed. The customer is provided with precise, relevant and accurate information, either locally or over industry standard communication links. Since an SVC is normally unmanned the focus of the HMI is to provide simplicity and accuracy when needed, rather than asking for attention on a continuous basis. Extensive diagnostic systems and event handling facilities make sure that the operator and/or the trouble-shooting engineer will always have correct and relevant information. This way the SVC will be reliable, available and perform its best under critical circumstances.

# Successful thyristor technology...
# ...the foundation of ABB's SVC lead

Decades of development work in semiconductor technology, especially in the field of power thyristors, has helped us achieve and maintain our market leading position.

Our high-power thyristors are precision manufactured and subjected to stringent testing. Their dependability has paved the way for further dynamic development of various applications incorporating thyristor technology.

For instance, we have applied this technology to HVDC, which involves both very high currents and ultra high voltages, plus exacting demands for reliability. The development of thyristor valves for Static Var Compensators is based on this know-how.

ABB has chosen to use the ETT (Electrically Triggered Thyristor) concept for both FACTS and HVDC referring to the vast available experience and track records of operation reliability.

Our range of thyristor valves for SVC includes water-cooled valves for different voltages which enables us to offer optimum solutions for the majority of applications.

For SVC applications, ABB has a comprehensive programme of high power thyristors in 4" and 5" sizes, voltage classes up to 6.5 kV, and current handling capabilities of well over 3000 A per device without any need of paralleling.

ABB offers both PCT (Phase control thyristor) and BCT (Bi-directionally controlled thyristor). BCTs are particularly suitable in situations where room is scarce and current handling capability moderate.

In the BCT, anti-parallel thyristors have been integrated on a common silicon wafer and therefore, only one thyristor stack is required instead of two (one for each current direction). With this arrangement, only half the number of thyristor housings is needed. The number of components in a valve is reduced, saving space as well as complexity.

## Cooling system

The cooling system consists of a closed loop piping circuit where a mixture of de-ionized water and glycol is pumped through the thyristor valves and outdoor water to air heat exchangers. There are two water-circulating pumps, one is in operation and the other is stand-by. In case of a pump failure an automatic switch over to the stand by unit will be initiated. A small portion of the flow is by passed through a water treatment circuit where the coolant is continuously de-ionized and filtered.

An outdoor dry air blast cooler is used, connected directly over the main circuit. Low noise fans are employed for reducing sound levels. All fans are individually controlled to ensure sufficient cooling with minimum losses.

The cooling system is automatically controlled by the MACH system.

## Directly connected SVC

A directly connected SVC is an SVC where there is no need for a step-down transformer to be connected between the SVC and the power system. ABB offers direct connection for system voltages up to 69 kV. This, of course, brings benefits to the project of a variety of kinds:

- A simplified SVC scheme
- A substantial hardware cost saving
- A saving in transportation cost, weight and volume
- A saving of site footprint
- A saving of plant losses
- No need to handle transformer oil
- No fire hazard
- No transformer maintenance costs
- Easy expandability since transformer rating and secondary voltage rise is not an issue when adding branches.
- Shorter lead times, not influenced by long transformer delivery times.

**Cooling water pump unit**

**Dry air blast cooler**

**Directly connected SVC**

## Shunt capacitors and reactors

**ABB has a comprehensive, high density capacitor programme, with up to 1 Mvar or more in one single can. This ensures a compact build-up of capacitor banks.**

**Low noise shunt reactors help fulfil the strictest requirements on noise reduction from SVCs.**

# Relocatable SVC

Power industry deregulation is introduced to meet growing market demands for flexibility. If this is to be the case in practice, technical solutions must also be flexible.

ABB's relocatable Static Var Compensator concept (RSVC) was conceived precisely for this purpose. This SVC mobility means dynamic voltage support can be obtained where it is most needed in the power grid to meet the current demand for network stability.

## Modular design

The truly mobile design of the RSVC enables an installation to be fully relocated within weeks. The RSVC is modular and transportable by road by means of standard vehicles. Its compact design and technical excellence guarantee quiet operation and low magnetic interference, thereby lessening the environmental impact.

## Easy to erect and commission

The modular design facilitates simple on site erection and commissioning. Prefabricated buswork and cabling ensures quick and easy inter-module connection.

The modular build-up also enables much of the equipment and system testing to be done in the workshop prior to delivery, which also saves time and money.

# Wind and Railways

For **wind power,** SVC aids in a number of tasks:

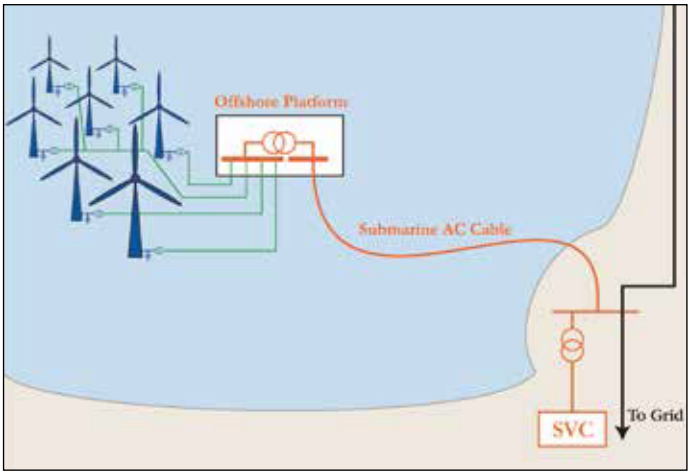
- Steady-state and dynamic voltage stabilization
- Continuous power factor control
- Enabling fault ride-through of the wind farm
- Power quality control by mitigation of flicker (caused by tower shadow effect, fluctuating wind, and/or starts and stops of WTGs); also harmonic reduction and reduction of phase imbalance.

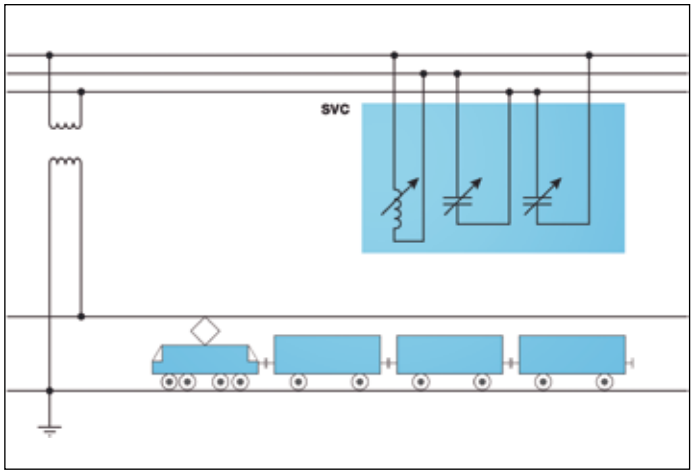
For **off-shore** wind generation, comprehensive AC sea cable networks call for additional elaborate reactive power control. The overall scope of reactive power control should encompass the wind farm just as well as the sea cables, to bring about a well regulated reactive power balance of the whole system, answering to the same demands on reactive power regulation as any other medium to large generator serving the grid.

## Railways

The increase in traffic on existing tracks combined with new high-speed rail projects mean rail traction is fast becoming an important load on electrical supply grids. This in turn is focusing a lot of attention on the efficiency of the catenary as well as the power quality of the surrounding grids. Trains taking power from the catenary need to be sure the supply voltages are stable and do not sag.

Voltage and current imbalances between phases of three-phase AC supply systems must also be confined in magnitude and prevented from spreading through the grid to other parts of the system. Likewise, voltage fluctuations and harmonics need to be controlled if they are to stay within the stipulated limits. This is where SVC comes in.




# SVCs for all applications

**As a result** of large power demanding industry development in central Norway, the demand in the region has increased dramatically and is expected to grow further. The power import capacity to the region has previously been limited for system stability reasons. As a remedy, two SVCs were installed in the 420/300 kV grid, each rated at -/+ 250 Mvar. With the installation of the SVCs, the power import capacity to the region under stable conditions has increased considerably.

The SVCs are equipped for damping of system electro-mechanical oscillations by means of Power Oscillation Dampers based on active power measurements. They are furthermore equipped with Q Optimizers, which enables coordinated control between the SVCs and mechanically switched shunt capacitors also employed in the grid. This ensures that the SVCs have maximum dynamic capability available to provide fast response to counteract grid disturbances.

**A very large SVC** was commissioned at the end of 2007 at a key substation near Rawlings, Maryland in USA. The installation enhances the reliability on the 500 kV transmission system – one of the most heavily-loaded in the PJM (Pennsylvania, Jersey, Maryland) Interconnection area – by quickly changing reactive power levels to control the line's voltage.

In addition to improving reliability, the SVC enables increased transmission capacity across the PJM region. Enabling more power to flow on existing lines is an efficient use of resources and an important step in keeping pace with the region's increased demand for electricity.

The SVC is rated at 500 kV, -145/+575 Mvar. The turnkey project was completed in 14 months, a record time given its scope, size, and complexity. The SVC is equipped with an advanced control system capable of controlling not only the operation of the SVC itself, but also the switching of two local 500 kV Mechanically Switched Capacitor banks (MSC).

**The Saudi Electricity Company** operates a power transmission system comprising 380 kV OH lines and underground cables. Operating conditions are special due to the hot climate, with up to 80% of the total load consisting of air conditioners. From a grid point of view, air conditioning is a particularly demanding kind of load, with slow voltage recovery, motor stalling or even voltage collapse in conjunction with short circuits in the transmission or sub-transmission network. To get to grips with this situation, three large SVCs have been installed in the region, with the explicit purpose of keeping the grid voltage stable as air conditioners all over the place are running at full speed. The SVCs, rated each at 110 kV, -60/+600 Mvar, were taken into service in 2008 and 2009.

**Two SVCs are in operation** in the power grid in Bretagne, France, one rated at 225 kV, -100/+200 Mvar and the other at 225 kV, -50/+100 Mvar. Grid voltage control is a key issue in the region and the SVCs have the following tasks:

- Allow fast supply of reactive power upon the appearing of faults in the grid.
- Absorb reactive power to control the grid voltage during low load or high level of distributed generation.
- Add flexibility and smoothness to grid voltage control.
- Prevent tripping of wind farms located in the region.

The SVCs have proved their usefulness in the power grid. They have sustained the network during situations with low grid voltage and all available MSCs connected. They have also brought increased flexibility into network management, and have increased the voltage stability due to TCR fine adjustment.

**A mining complex in Peru,** situated in the Andes mountains at an altitude of more than 4.000 meters above the sea level, is a major copper and zinc producer, one of the largest in the world. A prerequisite for production was the development of adequate utility infrastructure to feed the mine complex, as the feeding grid system was too weak to support the loads without proper measures taken. As a solution, an SVC was installed, rated at 45 Mvar inductive to 90 Mvar capacitive. Its purpose is to stabilize the 220 kV voltage at the mine feeding substation to within ± 5%, permitting safe operation of very large mining machinery even under the most restrictive power system conditions.

**Western Texas, USA** has an abundance of wind power. Adequate dynamic reactive power support is necessary to maintain system operation at acceptable voltage levels. To improve and maintain voltage stability, ABB has supplied and installed three SVCs in the system. Each SVC is rated at -40/+50 Mvar. Two SVCs are connected directly to 69 kV without any need for step-down transformers. The third is connected to the 34.5 kV tertiary winding of an existing 345/138 kV autotransformer. Each installation was initially scheduled to take 11 months from the time of initiation to the end of commissioning. Two of the SVCs were actually completed in just 10 months.

**A total of seven SVCs** were supplied to High Speed 1, the 108 km high-speed rail line between London, UK and the channel tunnel at Dover. With this link in operation, it is possible to travel between London and Paris in just over two hours at a maximum speed of 300 km/h. Six of the SVCs, each rated at -5/+40 Mvar single-phase are used mainly for dynamic voltage support. The seventh SVC, rated at -80/+170 Mvar is needed for dynamic balancing of asymmetrical loads between phases.

# ABB – the pioneer

## ...and market leader of SVC

ABB was one of the first companies to identify the importance of effective and rapid control of reactive power. As the market leader in static var compensation, ABB´s know-how in this field is acknowledged world-wide.

We commissioned the first large commercial thyristor-switched capacitor installation (1972) and also launched the first combined type Static Var Compensator, TCR/TSC (1979). Many of these are still in operation.

ABB SVCs have been installed by power utilities and industrial plants around the world for all existing voltages between 10 kV and 800 kV. And the technical and economy advantages of this technology are becoming increasingly recognized.

Today, close to 500 ABB SVCs are in operation or under installation all over the world. A selection of these are shown in the world map.

# Contact us

**ABB AB**
**FACTS**
SE-721 64 Västerås,
SWEDEN
Phone: +46 (0)21 32 50 00
Fax: +46 (0)21 32 48 10

**www.abb.com/FACTS**

A02-0100 E, 2015-03, Elanders Sverige AB

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# Exhibit PJL-6
# Description of the Use of a STATCOM to Supply Reactive Power and Dynamically Regulate System Voltages

# INTEGRATING HIGH LEVELS OF RENEWABLES INTO MICROGRIDS:

## Opportunities, Challenges and Strategies

**A GTM Research White Paper**

Sponsored by ABB

gtmresearch ABB

February 2016

## 3.4. STATCOM: Voltage Control

The power system considerations discussed in the two previous subsections deal with active power, but reactive power is also crucial to power system stability. When voltage levels drop in a power system, impacts are very visible to end users in the form of dimming lights, equipment malfunctions, etc. Utilities primarily depend on synchronous generators, as well as a range of assets (such as capacitor banks and static VAR compensators), to maintain voltages within certain limitations (generally 5% of unity).

When in grid-connected mode, microgrids can often depend on the utility for voltage support. However, in islanded mode, the microgrid operator must be able to independently support power quality and accommodate any changes to system voltage levels.

If a microgrid has on-line thermal generation (such as a reciprocating engine), the synchronous machine can be used to supply reactive power and dynamically regulate system voltages. However, if a significant amount of power is being generated from renewables, other devices must be used to generate these VARs. Several devices can be used in microgrids to supply these functions, including STATCOMs, which supply fast-acting continuous voltage regulation. If a microgrid already has an installed energy storage system, the front-end inverter of this flywheel or battery storage devices can typically fulfill this role when properly sized.

## 3.5. Standalone: Grid Referencing in Islanded Mode

When a microgrid is operating in grid-connected mode, the utility provides a convenient, reliable voltage and frequency reference to maintain microgrid synchronous operation. But when a microgrid is islanded from the grid, it must rely on its internal assets to provide this reference. Currently, most islanded microgrids rely on synchronous fossil-fuel-fired generators to provide that reference.

A unique challenge exists for islanded microgrids operating completely on renewable generation. Such a system is often entirely inverter-based and lacks any spinning generators. Therefore, it must rely on intelligent inverters coupled with storage, which can operate in voltage and frequency control mode to provide its own reference points. Managing this process is one of the core control functionalities of a fully renewable microgrid.

## 3.6. Smoothing: Capacity Firming

In addition to addressing how power intermittencies of 1 second or less affect system stability, a microgrid must also be able to manage overall renewable production patterns in relation to a system's portfolio of flexible and non-dispatchable load.

A microgrid must accommodate slight changes in the renewable contribution to the total grid capacity. When renewable input deviates from its forecasted pattern, energy storage or dispatchable generators are often used to bridge this gap. Depending on the size and duration of

# Exhibit PJL-7
# Company's Response to Advisors 6-1

Response of: Entergy New Orleans, Inc.
to the Sixth Set of Data Requests
of Requesting Party: Advisors to the Council
of the City of New Orleans

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Question No.: Advisors 6-1 Part No.: Addendum:

Question:

ENO's reliability studies provided as a CEII attachment to ENO's response to Advisors 3-3 indicate significant cascading reliability problems in 2017 and 2018 after the retirement of Michoud Units 2 and 3, and prior to the proposed in service date of NOPS, resulting from the occurrence of the specific NERC P2.3, P2.4 and P6 contingencies modeled and detailed in Entergy's presentation titled "Results of the transmission analyses performed in support of the NOPS in the 2019 study year."

a. Given the significant reliability problems that could occur in 2017 and 2018, prior to the in service date of NOPS, please explain why the retirement of Michoud Unit 2 was prudent in light of the study results?

b. Given the significant reliability problems that could occur in 2017 and 2018, prior to the in service date of NOPS, please explain why the retirement of Michoud Unit 3 was prudent in light of the study results?

---

Response:

The Company objects to this request on the grounds that it calls for a legal opinion. Subject to that objection and without waving the same, the Company responds as follows:

Michoud Units 2 and 3 were 51 and 47 years old, respectively. As stated in testimony, the units were deactivated sooner than the Company's planning assumptions due to maintenance, safety, and operational issues. In short, it was anticipated that the revenue requirement associated with maintaining these units would have exceeded the cost of purchasing in the MISO market during the time between deactivation of the Michoud units and the construction of NOPS; indeed, any investment would have been to attempt to sustain the units as short-term assets, as it would be expected that other parts of the units would begin to fail, requiring more capital investment.

The deactivation of the Michoud units is required to be reflected in the reliability assessments the Company must undertake pursuant to NERC TPL-001-4. NERC

Question No.: Advisors 6-1

Reliability Standard TPL-001-4 requires a Corrective Action Plan to address reliability issues associated with the TPL-specified planning events. Because the standard rightfully recognizes that reliability needs may arise more quickly than a solution can be implemented, a valid corrective action plan can include a plan to construct needed facilities, including a generating resource, even though there may be a lapse of time between the circumstance that created the need for the corrective action and implementation of the solution.

Moreover, the potential cascading reliability problems in 2017 and 2018, following the retirement of Michoud Units 2 and 3 arise only if a NERC category P6 contingency event were to occur. To avoid this contingency while NOPS is under construction, the Company could use consequential and non-consequential load shed. This would not be a preferred long-term solution, however, and the prudent, permanent corrective action in response to the category P6 contingency is to construct NOPS.

# Exhibit PJL-8
# Company's Response to AAE 8-12

ENTERGY NEW ORLEANS, INC.
CITY OF NEW ORLEANS
Docket No. UD-16-02

Response of: Entergy New Orleans, Inc.
to the Eighth Set of Data Requests
of Requesting Party: Alliance for Affordable
Energy

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Question No.: AAE 8-12 Part No.: Addendum:

Question:

Please discuss whether there were any generating units in the ENO service territory damaged by flooding during either Hurricane Katrina or any other flooding since Hurricane Katrina, describing

a. the units that were damaged,

b. when they were damaged,

c. the location of the units,

d. the cost to repair the damaged units, and

e. the time required to repair or replace the damaged units.

---

Response:

a. The generating units damaged were Michoud units 1, 2, and 3

b. These units were damaged during Hurricane Katrina in August 2005

c. All 3 units were located at Michoud Power Station in New Orleans.

d. Michoud 1 was never repaired because it was not economic to do so. The cost to repair units 2 and 3 totaled $10.7m

e. The time required to repair units 2 and 3 and their on-line dates in 2006 were:

| | | |
|---|---|---|
| Michoud 2 | 6 Weeks | On-Line April 17 |
| Michoud 3 | 16 Weeks | On-Line June 26 |

**Exhibit PJL-9**
**Company's Response to SIE 5-1 (b)**

ENTERGY NEW ORLEANS, INC.
CITY OF NEW ORLEANS
Docket No. UD-16-02

Response of: Entergy New Orleans, Inc.
to the Fifth Set of Data Requests
of Requesting Party: Sierra Club

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Question No.: SIE 5-1 Part No.: Addendum:

Question:

Please reference your response to SIE 4-14, concerning disconnect of transmission into New Orleans during and after Hurricane Gustav:

a. What is the proportion of New Orleans' peak load as a share of the total peak load of the DSG load pocket? As a proportion of the total ENO peak load?

b. Please state the extent of loss of load resulting from disconnection of the lines noted in response to SIE-14, and indicate if it included all of the DSG load pocket, and if it also included additional load within the Amite South load pocket. Please provide an explanation of the extent of load loss resulting from the "islanding" and how it encompassed more than just the City of New Orleans.

c. Please provide any available reports produced by or on behalf of Entergy that detail the Hurricane Gustav restoration efforts.

d. If applicable, please provide any additional analyses or information beyond that provided in response to c) above that describes broadly the sequence of electric power restoration feeding into either the DSG load pocket or New Orleans itself after Hurricane Gustav, including use of generation assets in New Orleans or within the DSG load pocket, and the use of transmission lines feeding into the DSG load pocket or into New Orleans.

e. In particular, if not provided in the responses to c) and d) above, provide actual or estimated levels of demand that existed in each of New Orleans and the entire DSG load pocket as each or groups of the transmission lines reconnecting New Orleans to the greater Entergy system were placed back in service.

f. Please state the reason why each, or all, of the lines into New Orleans were disconnected, and what was required to allow each, or all, lines to be placed back into service.

g. Please, in an abbreviated manner, summarize the damage to the distribution system infrastructure within New Orleans or within the DSG load pocket or within the entirety of the "islanded" area that existed after all of the noted lines were disconnected, and state the extent to which demand was not able to be served because of distribution system damage.

---

Response:

Information responsive to this request has been designated as Highly Sensitive Protected Material under the terms of the provisions of the Official Protective Order adopted pursuant to Council Resolution R-07-432 relative to the disclosure of Protected Materials and is being provided in accordance with the same.

a. For the 2018 summer peak condition, the forecasted peak New Orleans load is expected to be 33.54% of the peak DSG load. The New Orleans load constitutes 100% of the ENO peak load.

b. With reference to the transmission lines listed in the Company's response to SIE 4-14, please note their tripping, which led to the island formation, did not result in loss of load. In the case of the Gustav Island, there was a sufficient amount of generation available to serve the load in the electrical island, which mitigated against widespread outages. As mentioned in pages 13 and 14 of Mr. Charles Long's Direct Testimony, the island formed during Gustav extended beyond DSG and included load and generators along the industrial corridor southeast of Baton Rouge.

c. See the highly sensitive attachments.

d. Please see the response to part c above.

e. The Company is not in possession of the requested information.

f. Following a storm, the Company's efforts are focused on restoring power in the quickest manner possible. Thus, the Company does not spend the tremendous amount of time that would be necessary to document specific reasons for the tripping of every transmission line affected or the measures that had to be undertaken to re-energize lines.

g. As is likely the case with any major storm, the Company sustained damage to its distribution system during Hurricane Gustav. See attachment provided to subpart (c). Distribution damage after a storm, however, does not detract from the ability of local generation to aid in storm restoration, which is an entirely different issue.