STATE OF CONNECTICUT
CONNECTICUT SITING COUNCIL

Northeast Utilities Service Company Application to the Connecticut Siting Council for a Certificate of Environmental Compatibility and Public Need ("Certificate") For The Construction of a New 345-Kv Electric Transmission Line Facility and Associated Facilities Between Scovill Rock Switching Station in Middletown and Norwalk Substation In Norwalk, Including the Reconstruction of Portions of Existing 115-kV and 345-kV Electric Transmission Lines, the Construction of Beseck Switching Station in Wallingford, East Devon Substation in Milford, and Singer Substation in Bridgeport, Modifications at Scovill Rock Switching Station and Norwalk Substation, and the Reconfiguration of Certain Interconnections

Docket No. 272

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ANSWERS OF ABB, INC. TO ISO NEW ENGLAND INC. FIRST SET OF INTERROGATORIES TO ABB, INC. DATED OCTOBER 29, 2004

1. Does ABB agree that the need to install series reactors to mitigate short circuit indicates that the HVDC solution does not, in itself, reduce short circuit levels? If not, please explain why not.

   No, HVDC circuits contribute significantly less to system short circuit levels than do AC circuits of comparable transfer capacity. An inverter terminal of an HVDC link can contribute only up to its rated load current to the three-phase symmetrical short circuit level at the point of interconnection. This is because the line current is controlled. Furthermore load current contribution can be quickly reduced before circuit breakers are called upon to interrupt the fault current by fast HVDC control action if needed. On the other hand, each terminal of an AC circuit can contribute many times its rated current to the short circuit level at the point of interconnection being limited only by its circuit impedance. This is especially true of AC cable circuits, which have lower impedance than do overhead lines. The series reactors in the converters, so called phase reactors, are not installed to reduce short circuit currents from the converter to the AC grid. The purpose of these reactors is to filter high frequency harmonics.

   Depending on the transformer connection, there may also be a ground fault contribution. This is true for an HVDC link where coupling transformers are used to match the system voltage or for an AC interconnection with a substation at its terminals. Short circuit contributions are cumulative. Therefore, if several circuits are added together with generation, each will contribute to the short circuit level. The contribution from the DC circuits will be significantly less than from the AC circuits. The contribution from the generation will be the same with the highest contribution being at the connection voltage. In the case of the SWCT, if the generation is connected at 115 kV instead of 345 kV, the contribution from the generation will be higher at the 115 kV level due to it not being limited by the 345/115 kV transformer impedance.

Use of series reactors was considered an acceptable method and is also currently approved for use at Bridgeport Harbor Unit 2 (this is included in the system data provided by NU). The ABB suggested solution used series reactors at Bridgeport Harbor Unit 3 in order to meet the study scope criteria to reduce the fault levels at Pequonnock 115-kV bus to about 90% of 63kA. As a reference, with the proposed Phase II all-AC solution, the fault level is 96% of 63kA. Other methods to limit short circuit without series reactors are available, such as the use of ungrounded transformers, and would produce results comparable to levels the Phase II all AC solutions provide.

2. There are system constraints that result in increasing amounts of conditional dependencies among operation of generators in Southwestern Connecticut ("SWCT"). Doesn't the addition of multiple HVDC terminals make system operation more complicated by actually creating additional conditional dependencies that would require very complicated and careful coordination of the outputs of all of area generators and all of the HVDC terminals?

   No. Multiple HVDC terminals enhance operational flexibility and controllability of the system. It is envisioned that the HVDC terminal outputs would be scheduled by ISO-NE within the ISO's security constrained dispatch function. The proposed HVDC solution will not increase the generation dependencies described by ISO-NE. The ability to control power flow will provide flexibility to deal with and the potential to reduce the generation dependencies.

   Network constraints consist of circuit transfer limits, e.g., thermal limits or stability limits with allowance for contingencies. Unlike with AC transmission, a DC circuit cannot become overloaded since its power flow is controlled. The controllability of the DC transmission (or AC transmission with phase angle regulators) provides additional operational flexibility of the constrained network. With AC transmission, the only recourse available to system operations when confronted with a transmission constraint is generation re-dispatch. Security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) can be used (and is used) to schedule controllable transmission elements, e.g., phase angle regulators (PAR) and HVDC, just as well as generation.

   The power flow study performed by ABB investigated 24 different scenarios of generation dispatches and transfer conditions provided by NU and UI. The results of the contingency analysis (based on the contingency list provided by NU/UI) do not show any new overload or voltage problems beyond those that are also present with the all-AC Phase II solution.

3. The existing system in SWCT has short circuit problems that limit the ability to interconnect generation. Assuming that ABB agrees with this observation:

   a. Please explain how the HVDC proposal can support the addition of generation without requiring dedicated HVDC terminals, thereby creating even more complex HVDC facilities with more than three terminals?

   b. Wouldn't such a multi-terminal facility create a common mode failure that would result in the simultaneous loss of the line, all of the HVDC terminals, and the generator? Please explain.

   a) From a reliability perspective, bulk power transmission, whether AC or DC should not be tapped indiscriminately for connection of generation. However, if the underlying transmission is inadequate to support the new generation, it should be connected through an intermediate switching station or substation rather than a tap. With HVDC, this would require another converter station to connect into the DC transmission. If there are several generators relatively close to one another, it is usually more economical to reinforce the underlying transmission to form a collector system before installing a substation or a converter station to access the overlying bulk power transmission. Option 3 as submitted in the ABB reports allows addition of generation without adding any converter terminals.

   b) Yes, it could depending on the location and nature of the fault or failure. If the fault is on the AC side of the converter within its protective zone or involves the converter auxiliary systems, then this results in loss of the affected converter only. However, if the fault is on the DC side of the converter then the whole circuit will be lost unless there are fault isolation switches on the DC side since cable faults are not temporary. If the converter station were the sole outlet for the generator as in Options 2a and 2b of the ABB reports, then the generator would be lost as well. If not, as in Options 1, 2 and 3, then the generation could remain on line at a level commensurate with the remaining transmission capacity.

4. Wouldn't the addition of additional load-serving HVDC terminals result in a more severe common mode contingency involving the simultaneous loss of the line and all of the HVDC terminals? Please explain why or why not.

   Options 1, 2 and 3 from the ABB reports have two or three parallel independent circuits. There is no common failure mode that will result in the simultaneous loss of more than one circuit. In option 2a and 2b the connection with Singer or Devon could be lost. The maximum amount of power that can be lost is represented by the capacity of the parallel circuits that is 370 MW or 530 MW pending the chosen option.

5. Wouldn't changes in system conditions, such as change in generation dispatch or load level, potentially require adjustment to all of the HVDC terminals, as suggested in Table 3-1 of the Power Flow Analysis report? Please explain why or why not.

   It is envisioned that the HVDC terminal outputs would be scheduled by ISO-NE within the ISO's security constrained dispatch function. The HVDC terminals provide additional operational flexibility and controllability of the system. In addition the HVDC lines cannot be overloaded. One control strategy can be to program the HVDC lines to emulate an AC line. Another option would be to emulate generator dispatching. This second option is similar to what needs to be done to the dispatch of generators as the load level changes or there are equipment outages. The dispatch of the HVDC terminals would be performed in conjunction with the generators, using the same basic market operation tools that have Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) functions. In the most basic terms, dispatch of the HVDC terminals would be very similar to dispatching of a generator.

6. The study report indicates that overloads could not be resolved by dispatch, but that they could be resolvable by runbacks of the DC. Does ABB agree that it is possible that a runback of an embedded DC facility could produce an overload or insecure condition in another part of the system, at or near another affected terminal, and if so, is this not a significant consideration?

   Disagree. As indicated in the answer to question 5, it is envisioned that the HVDC terminal outputs would be scheduled by ISO-NE within the ISO's security constrained dispatch function. In a security constrained dispatch mode any overloads on the system should be within the short-term emergency operating limit for dual or multiple contingencies and long-term emergency operating limit for single contingencies. Depending on system conditions, loss of any AC circuit, DC circuit or generator could produce an overload or unsecured condition. Redispatch of generation or controllable DC transmission may be required to relieve an overload or reach a secure state. With the DC transmission another level of operating flexibility is available. If the overload must be resolved quickly, then a runback (or run-up) function may be required. . However, a planned runback control feature would not be implemented unless validated though system studies and approved by the appropriate authorities. In study performed by ABB a very small sub-set of operating scenarios required use of remedial actions such as runback of the HVDC to bring the system to a secure state. Well-designed remedial action schemes should not cause overloads or insecure conditions in other parts of the system. It is expected that any remedial scheme using runback of HVDC would not have adverse impact on other parts of the system.

7. Has a VSC HVDC converter of the 400 to 500 MW size been installed anywhere in the United States, and has such a converter been installed anywhere else in the world? If so, please specify where and describe the facility.

   No. The development of VSC HVDC converters parallels that for conventional HVDC converters. Once the basic technology was proven, increases in current and voltage levels followed. The Murray Link and Cross Sound projects operate at over twice the voltage and current levels than do the Gotland and Direct Link projects.

   The largest VSC HVDC Converter installed today is the 330 MW Cross Sound converter that was designed during 2000 and commissioned in August 2002. Consistent with traditional development strategies, developments over the last four years have resulted in using larger semiconductors and therefore an increase in the converter size to 500 – 550 MW pending application.

8. Has the cable at the nominal DC voltage proposed been installed anywhere in the United States, and has such a cable been installed anywhere else in the world? If so, please specify where and describe the facility.

   The nominal voltage proposed for SWCT is 150 kV DC. This voltage has been used in two commercially operating VSC HVDC projects.

   - Murraylink in Australia commissioned Oct 2002 with 2 X 177 km 150 kV underground cable.
   - Cross Sound Cable in US commissioned August 2002 with 2 x 40 km 150 kV submarine cable.

9. Are there any other multi-terminal VSC HVDC lines in operation anywhere in the United States or in the world? If so, please specify where and describe the facility.

   No. However, many of the principles developed for multi-terminal conventional HVDC are directly applicable to VSC HVDC, e.g., master power control, loss allocation, fast-prioritized power order reallocation and protective isolation. Furthermore, the attributes of VSC HVDC as developed by ABB simplify multi-terminal control and coordination. These include no residual earth current constraints, less dependence on communication, multimode regulators with built in back-up modes, no minimum power order constraint, no polarity reversal required for power reversal, and no commutation failures. There is one characteristic that differs with the VSC multi-terminal operation – DC ground faults cannot be cleared by converter control action and must involve AC breaker action. Note that only Option 2 from the ABB reports includes multi-terminal configuration.

10. Are there any other places in the United States or elsewhere in the world where multi-terminal VSC or conventional HVDC lines are operating in parallel with another multi-terminal VSC or conventional HVDC lines? If so, please specify where and describe the facilities.

Yes. The Quebec – New England Phase II (conventional HVDC) consists of two multi-terminal circuits operating in parallel, Pole 1 and Pole 2. These two circuits share a common return circuit consisting of the DC neutral and ground electrodes but otherwise can operate independently. Note that Option 1 and 3 from the ABB reports do not include multi-terminal configuration.

11. What is the itemized breakdown of the estimated HVDC option cost, including cable installation, construction and all substation work?

The estimated prices for the different parts of the five options were presented in the ABB October report. The table of estimated budgetary prices from the ABB report is repeated here:

Option	No of converter stations and power	Conv stn price (MUSD)	No of cables	Cable price (MUSD)	Cable installation (see note) (MUSD)	Total price range (MUSD)
Option 1	10x370 MW	510	3x2	90	180-230	780 - 830
Option 2	10x370 MW	510	3x2	90	180-230	780 - 830
Option 2a	8x370 MW	410	3x2	90	180-230	780 - 830
Option 2b	6x530 MW	350	2x2	100	180-230	630 - 680
Option 3	6x370 MW	310	3x2 (short)	55	100-130	465 - 495

Note: The installation price range is based on 100% cable duct installation. This price can be lower if direct burial of the cables is selected as the method.

In addition to the lists in the report on what the prices include, the following applies.

The converter prices include:

- Labor
- Material
- Equipment
- Overhead
- Contingency costs

The cable prices include:

- Labor
- Material
- Equipment

- Overhead
- Contingency costs

The cable installation prices include:
- Labor
- Material
- Equipment
- Overhead
- Contingency costs

The following are not included either in converters, cables, or cable installation:
- Real property acquisition
- Applicable taxes
- Applicable permits

The cable installation price range is based on the July 2004 pricing of Phase I, Section II (115 kV UG Cable Bethel to Norwalk), which was tendered by ABB for execution in 2004 and 2005. The use of a range reflects a higher degree of cost uncertainty compared to converter and cable prices. A more precise price would need detailed studies of the actual route.

The basic preconditions for the cable installation price estimations for Phase II have been:
- Totally 253,000 cy of excavation (an approx 54 miles x 6 feet deep x 4 feet wide trench)
- 10% rock volume, removed by means of blasting
- Native backfill above duct-bank encasement
- Similar methods and constraints as for the civil works for Phase I

Based on experiences from other installations, direct burial of the cables can reduce the cable installation price to a level below the price range given in the table above. This alternative has, however, not yet been explored for this project, Southwest Connecticut Phase II. We believe it could be of interest to better investigate how experiences of direct burial, gained in other projects, potentially could be applied in Southwest Connecticut.

12. Please explain how the HQ-Sandy Pond multi-terminal conventional HVDC line is scheduled and operated.

    The facility has been tested and is fully functional for multi-terminal operation. The facility owners and the needs of ISO-NE and Hydro Quebec determine the day-to-day or commercial operation of the facility. Power orders are entered for each operating terminal. Ramp rates are selected. One station is selected to control the voltage. One station is selected to supply the losses. Rectifier or inverter operation is selected for each station depending on the desired power direction. Converters are started and stopped or paralleled or de-paralleled as desired.

13. Please describe the system changes that would result in a need to change the scheduled HQ-Sandy Pond flow and describe what other system adjustments would also be needed if the scheduled flow were changed.

    As with any asynchronous interconnection, interchange schedules must be accompanied by corresponding generation/load changes or vice versa. With multiple interconnections interchange can be shared for optimal system operation.

14. Please explain how the proposed embedded multi-terminal VSC HVDC line would have to be scheduled and operated.

    The controllability of the HVDC transmission provides an added degree of freedom in optimal operation of the network. It is envisioned that the HVDC terminal outputs would be scheduled by ISO-NE within the ISO's security constrained dispatch function. The dispatching of the HVDC terminals will be performed in conjunction with the generators, using the same basic market operation tools that have Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) functions. In the most basic terms, dispatching the HVDC terminals is very similar to dispatching generation units within ISO-NE. That is, ISO-NE will provide the Day Ahead schedules and Real Time adjustments determined by the SCUC and SCED to the operator of the HVDC terminals, in a fashion similar to the way ISO-NE is currently dispatching generators. The energy management and SCADA system can also carry out the schedule ordered by ISO-NE for the HVDC system directly and automatically. The schedules determined for HVDC through the security constrained dispatch function will always maintain the system in a secure state i.e. no overloads, no voltage or stability problems and the ability to withstand single or multiple contingencies.

15. Please describe what system changes would result in a need to change the scheduled embedded VSC HVDC flows and describe what other system adjustments would also be needed if the scheduled flows are changed.

    The same changes that would also result in a need to adjust the dispatch of generators, such as load level variations, equipment outages or other system events may also require VSC HVDC schedule flow adjustments to maintain secure and efficient system operation, if required. The HVDC will be scheduled within the Security Constrained Dispatch algorithm used by ISO-NE. This algorithm will determine a revised schedule for HVDC (as well as all generating units) approximately every 5 minutes. The Security Constrained Economic Dispatch algorithm reschedules the system every 5 minutes to follow changes in load level and equipment availability. Note that the same changes would also result in a need to adjust the dispatch on generators. As generation is committed and dispatched to serve load, the controllable DC flows would be scheduled to maintain secure and efficient system operation. The DC transmission can also be rescheduled to a new state following contingencies if desired or needed.

16. Please describe how and why the operation of HQ-Sandy Pond, Highgate, Eel River, Madawaska, and Chateauquay are similar but would be different from the operation of an HVDC facility embedded in the middle of a free flowing unregulated network.

The referenced ties are asynchronous ties between Quebec and the Eastern Interconnect system and scheduled changes must also be accompanied by generation/load changes in the respective networks. Schedule changes on synchronous (embedded) HVDC links such as Vancouver Island, Pacific DC Intertie, Square Butte, CU and Cross Sound need not be accompanied by similar generation/load changes. Synchronous links can be adjusted for optimum power flow, lower losses or security reasons without coordinated generation changes.

17. Table 3-1 in the Power Flow Analysis report indicates a substantial change in the relative schedules of the HVDC terminals for the various cases. Doesn't this indicate that a substantial number of multiple simultaneous HVDC terminal schedule changes could potentially be required if there was an event such as a loss of a generator that represented a change similar to the difference between the cases? Please explain why or why not.

As explained in the answer to question 15, The HVDC will be scheduled within the Security Constrained Dispatch algorithm used by ISO-NE. This algorithm will determine a revised schedule for HVDC (as well as all generating units) approximately every 5 minutes. The Security Constrained Economic Dispatch algorithm reschedules the system every 5 minutes to follow changes in load level and equipment availability.

18. Does ABB agree that Table 3-1 suggests that multiple and frequent simultaneous HVDC terminal schedule changes could potentially be required as load level changes throughout the day and generation levels vary? Please explain why or why not.

As explained in the answer to question 15, The HVDC will be scheduled within the Security Constrained Dispatch algorithm used by ISO-NE. This algorithm will determine a revised schedule for HVDC (as well as all generating units) approximately every 5 minutes. The Security Constrained Economic Dispatch algorithm reschedules the system every 5 minutes to follow changes in load level and equipment availability.

19. Is it practical to assume that in the embedded parallel multi-terminal HVDC solution for SWCT, the terminals could be set "once in the morning" and then left unchanged or unattended by the system operators? Has ABB considered the potential consequences of such an unchanged or unattended operation, and if so, what are they?

No. While this may be the case if one of the terminals or links was used to deliver base load capacity, it certainly is not the general case for power transfer levels. On the other hand, the reactive power or voltage reference for each terminal could be set to a desired level and left unchanged. This is true not only for multi-terminal Option 2 from the ABB reports but also for two-terminal such as Options 1 and 3.

As explained in the answer to question 15, The HVDC will be scheduled within the Security Constrained Dispatch algorithm used by ISO-NE. This algorithm will determine a revised schedule for HVDC (as well as all generating units) approximately every 5 minutes. The Security Constrained Economic Dispatch algorithm reschedules the system every 5 minutes to follow changes in load level and equipment availability.

The HVDC terminals will be dispatched in a fashion similar to how ISO-NE is dispatching generators today. The HVDC terminals will be dispatched as often as the generators are dispatched. Since the HVDC terminals and the generators will be dispatched together at the same time in a security constrained manner automatically and regularly by market operation software tools, the possibility and probability of not making the necessary scheduled dispatch changes for the HVDC terminals is no more likely than those for generators. Unchanged or unattended operation of the HVDC is possible but would result in loss of controllability and flexibility in operating the system – in this scenario control of flows will be done solely using generation re-dispatch. This is not recommended, as HVDC flows can be scheduled as easily as generation and gives an added degree of flexibility to system operation.

20. Is it fair to assume that the proposed embedded parallel multi-terminal HVDC solution in SWCT require constant operator vigilance, near-perfect scheduling, decision-making and simultaneous action to be operated in a manner consistent with applicable NERC and NPCC reliability criteria? Please explain why or why not.

No. What is fair to say is that the HVDC system does offer additional operating flexibility, if desired. The HVDC links should be scheduled to support the generation dispatch and load patterns as part of an optimum power flow. This can be done by operator action based on schedules determined by SCED. With respect to meeting reliability criteria, all facilities would be designed to meet NERC and NPCC criteria, where applicable. Other synchronous or embedded DC systems are operated today in full compliance with NERC criteria and may include fast remedial action by automatic control or protection, e.g. runback or run-up where necessary to respond to some contingencies. It is also fair to say that the higher the number of links or terminals, there may be a greater demand on the operator(s) depending on the desired mode of operation. As an alternative to manual transmission scheduling, the DC links can be made to emulate an AC line behavior by linking the power order to generator output or phase angle differences between terminals. With the multi-terminal Option 2, power flow can be reallocated following loss of a terminal in the same prioritized way as for conventional HVDC.

21. Does ABB have any operational experience with respect to an embedded parallel multi-terminal HVDC solution such as that proposed for SWCT, and if so, what additional operating considerations does ABB believe the solution imposes on system operators, and has ABB encountered any operational difficulties?

    It is the ABB customers that have the operational experience with parallel synchronous (embedded) two terminal HVDC links, e.g., CU and Square Butte. Operational difficulties have been encountered with the Phase II HVDC link between Quebec and New England. Phase II can operate synchronously with two parallel circuits, pole 1 and pole 2, between Radisson and Nicolet while the third terminal, Sandy Pond operates asynchronously in parallel with other HVDC links. The difficulties encountered were with Phase II scheme related to the adverse impact DC residual ground currents flowing between Radisson and the La Grande during unbalanced operation and effectively precluded that operational mode. Another factor that complicated operation was the need to switch DC polarity in order to reverse power. Neither or these factors apply to the multi-terminal Option 2 proposed for SWCT. The HVDC will be scheduled within the Security Constrained Dispatch algorithm used by ISO-NE and therefore requires no additional operational burden on ISO-NE operators. The use and incorporation of various control features of HVDC for remedial actions following contingencies or system disturbances need to be studied, documented and incorporated into ISO-NE operating protocols. It is to be noted that the control features of HVDC will give ISO-NE operators far greater flexibility of operation than they have today. The VSC HVDC solution proposed for SWCT will have the ability to absorb or produce VARs, ability for fast reactive support similar to STATCOMs and even black-start capability.

22. If ABB does not have any direct operational experience with respect to an embedded parallel multi-terminal HVDC solution such as that proposed for SWCT, does ABB nevertheless know what additional operating considerations such a solution may impose on system operators, and what operational difficulties have been encountered in connection with such a solution?

    Two areas need to be addressed in order to implement multi-terminal VSC HVDC transmission as proposed for Option 2. These are a) detecting and determining the sequence for clearing and isolating DC side faults and b) determining a post contingency operational level following loss of a converter without a master control. Alternatives that may be considered would be to a) trip the multi-terminal circuit for DC side fault and b) rely on the master control to establish a new operating point following loss of converter. On a higher level, the DC links would need to be included in the SCUC and SCED programs and incorporated into the ISO-NE EMS system.