On-line Voltage Regulation: The Case of New England

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Abstract: This paper reports results of a joint industry-university study regarding possible steady-state voltage problems in portions of New England. Circumstances under which these problems may occur are described first; this is followed by a review of the operating and planning practices for preventing their occurrence.

These engineering practices are compared with an analytic approach whose application to the same operating problems is presented in this paper. The results represent a verification of the method's potential to serve as a powerful tool for predicting steady-state voltage problems created by contingencies and for determining locations and amounts of available reactive power compensation and generation-based voltage support necessary to bring load voltages close to their pre-contingency values. The method is potentially useful for automating search for solutions under the operating conditions not previously experienced by a human operator and could be used as a basis for on-line steady-state voltage regulation. This is an important qualitative improvement over the presently practiced open-loop scheduling for preventing steady-state voltage problems.

Keywords: Power system control, Power system monitoring, Power system planning, Power system stability, Reactive power control, Industrial power system reliability, Voltage control, Load flow analysis.

I. Introduction

In this paper we study steady-state[1] voltage problems in portions of the New England system that arise with several nuclear plants out of service over prolonged periods of time. This situation has prompted engineers to assess the worst case situations and install new capacitive support at several locations. The engineers have identified the worst case situations and have taken active measures to prevent potential voltage problems. We describe these engineering solutions first.

Next, we consider computer-based methods for detecting voltage problems as they evolve and for computing remedial actions to minimize their effects. The software developed could be used for both planning and operations purposes. Its main feature is the ability to predict the post-contingency problems fast and suggest most effective real-time remedies.

Based on the results obtained, we suggest that it would be possible to begin to rely on on-line voltage regulation in place of the presently practiced preventive voltage control.[2] For example, it is likely that the operating strategies based on on-line voltage regulation[3] will allow for higher power transfers than when the system is operated based on open-loop scheduling since some contingencies are no longer limiting when remedial actions are accounted for. The suggested voltage regulation by means of capacitor switching and by changing set-point values of voltage regulators on power plants is illustrated in this paper.

In section II, we first give a brief history of voltage problems in New England, and describe in considerable detail the problems created when a number of nuclear plants are out of operation. Next, in section III we describe present operating and planning practices in New England for maintaining acceptable voltage; since these are not the same throughout the system, we particularly emphasize the operating practices in CONVEX, the satellite control center responsible for voltage control in the area where problems of interest may occur. In section IV we describe the preventive engineering solutions for preventing specific voltage problems created by the nuclear plants being out of service. In section V we describe the solutions based on an analytic method and software developed at MIT. Finally, in section VI we compare the results of the two.

II. Past and potential future voltage-related problems

New England (NE) has had a general history of successful planning and operations for avoiding voltage problems. The problems experienced in real-time operations are the result of (1) high reactive power demand in particular portions of the system, and (2) large reactive power losses caused by heavy power transfers over long distances.

As these events are predicted, system planners upgrade the system to ensure reliable customer service even when hot days occur and when generating plants are out of service. The installation of additional capacitive support

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[1]The problem of voltage stabilization is not a subject of this study. It is assumed that voltage stabilizing is done by various primary voltage controllers. The main question concerns methods of changing the set-point values of these controllers to prevent steady-state related voltage problems.

[2]The main problem with open-loop scheduling comes from the fact that the system must be operated conservatively in case something happens in the future.

[3]Also referred to in the industry as *remedial actions*.

has been required to support the expected power transfers and to avoid voltage problems.

The case of high reactive power demand was experienced in the summer of 1984, resulting in (scheduled) rolling brown-outs in Massachusetts. The Rhode Island- Eastern Massachusetts- Vermont Energy Control (REMVEC) portion of the NE system experienced a sequence of rolling brown-outs because of the reactive power deficiencies in its area. To avoid this from happening in the future, Boston Edison Co. installed several new large capacitors. At the same time, research at MIT was initiated to develop a method for detecting locations of most critical steady state voltage problems and for computing the most effective remedial actions, such as capacitor switching and adjusting set-point values on voltage regulators of power plants in the effected area as the reactive power demand varied; the objective of the method was to maintain load voltages as close to the nominal operating conditions as possible by means of these remedial actions. This was done in close collaboration with several New England utilities. The software developed was installed at REMVEC, however it is not in active use at present [6]. The software is not being used partly because the operators are generally hesitant to switch capacitors frequently. Moreover, the practice of changing set-point voltage values for voltage regulators on power plants is not common. This is in contrast with practices in several European countries where the set-points of voltage regulators are changed in a closed-loop automated way [1], [2].

More recently, several nuclear plants, Connecticut Yankee and the three Millstone units, have been taken out of operation and this has created power shortages in the Connecticut area of CONVEX and has brought the system close to its operating limits. Specifically, engineers have been familiar with the potential for unsatisfactory voltage performance in Connecticut for over twenty years. Operating procedures have been developed to ensure that satisfactory voltages are maintained on the system for all events. The procedures have and are evolving. The early document had simple instructions–which may have put too much generation in service for some conditions, however, the procedure did ensure reliability. Later documents were more complicated and gave "credits" and "charges" for having different combinations of generators in services to develop a load level. Based on the load level, CONVEX was required to have zero to five or six of seven generators in service. Since these seven generators include Connecticut Yankee and the three Millstone units a different approach was needed. The most recent operating instructions have been developed based on transfer limits.

For Connecticut transfer limits, import from New York can be either beneficial or detrimental depending on a number of system conditions and the amount of the import.

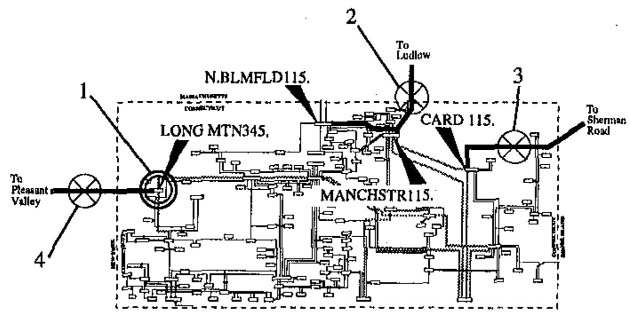

Fig. 1. The geographic locations of the four voltage-related contingencies in Connecticut

Based on the earlier studies done by Northeast Utilities (NU) operating engineers, the outage of the three Millstone units would lead voltage concerns for summer operation. Under the high power transfer conditions, the following four contingencies are considered as the most critical under the high power transfer conditions, Fig. 1:

1. *Long Mountain stuck breaker*[4] In this case, a fault on one of the circuits terminated at Long Mountain substation and the failure of a circuit breaker are studied as the contingency. In addition, the two 345/115 *kV* auto-transformer at Plumtree and one 345/115 *kV* autotransformer at Frost Bridge are disconnected.
2. *Loss of Card to Sherman Road 345 kV transmission line.*
3. *Loss of Ludlow to Manchester to North Bloomfield 345 kV transmission line.*
4. *Loss of Long Mountain to Pleasant Valley 345 kV transmission line.*[5]

When any one of these contingencies occurs, it may be difficult to maintain voltages within their acceptable limits. These cases were recently used by the NU engineers for re-enforcing the system by adding new capacitor banks and for re-configuring the line connections, as described below.

III. Present operating and planning practices

Except for the very few truly dynamic problems, majority of voltage problems in NE is steady-state and geographically localized. This allows for distributed voltage regulation by local control centers. The Independent System Operator (ISO-NE) remains responsible for overall performance of the system, however, after evaluating the procedures for the local control centers, he delegates the voltage control to the local control centers. Over the years, operating engineers and operators have developed insights for how to regulate voltages in their areas for "best" performance. Typically, the term "best" implies different things in different parts of the NE system, and is usually result of considering several factors characteristic to each specific subsystem. Moreover, engineers have developed strong understanding of potential problems in

[4]This is the most severe out of the four contingencies considered.

[5]This contingency often results in high voltage problems in western Connecticut area.

their area and have developed corresponding strategies to deal with these problems as they evolve in real-time operations. In Eastern Massachusetts, for example, the potential for voltage problems created by high reactive power demand on hot summer days is a concern, but, at the same time, large amounts of line charging from an extensive transmission cable system leads to the potential for high voltages during lighter load periods. Vermont has a variety of voltage-related problems because of heavy real power imports, including those from Canada via a DC line. The effects of voltage problems in Maine are relatively isolated from the rest of the system. The Connecticut area is challenged by heavy imports. These imports are the result of generation being out of service either for equipment failures or economic reasons.

In this paper we analyze in detail voltage problems in the Connecticut area only.[6]

A. "Nominal" voltage profile: operations vs. planning

It is particularly interesting that the desired voltages under normal operating conditions are not determined using the same factors in all areas. Consequently, NE does not have a single standard for regulating voltages, a situation typical in all other parts of the U.S. system. Possibly one unifying definition to all is that a satellite operator considers a "normal" operation to be any combination of system load/equipment status for which the $(N-1)$ security criterion must be met; namely, no matter what conditions the system is under in real-time operations, these are acceptable as long as the system remains functional for at least 30 minutes without affecting any customers after any single contingency takes place. This is what is known as the preventive open-loop scheduling; if a contingency happens in the future, the customer should not be effected, even prior to any other corrective actions. For example, a situation with higher than expected demand is still "normal" to the system operator responsible for ensuring system reliability in real time.

For planners, on the other hand, "normal" conditions are defined for the expected demand pattern and all available equipment assumed functional. As the demand varies significantly away from this expected pattern and as the equipment gets taken out of service, there is generally significant discrepancy between the planned and operating "normal" conditions. It is for these reasons primarily that engineers use conservative static and dynamic reserves to meet the $(N-1)$ security condition in real-time operations. The engineers usually use the worst case scenario for determining these reserves. The operating mode is preventive, that is, reserves are created without relying on real-time corrective actions. An example of preventive versus remedial corrective action related to voltage control would be that reactive power reserve/capacitive support is used without relying on additional real-time switching of capacitors following a contingency, even when this is possible in the cases where the problem is strictly steady state and the time is not critical.

[6]For an earlier study of voltage problems in REMVEC area, see [5].

B. Methods presently used for defining "nominal" voltage profile

An assessment of methods for regulating voltage in New England shows that methods have been developed over the years for regulating voltage so as to make the most out of what is available and, also, for upgrading the system for voltage support. Most of these methods are result of extensive load flow studies, and operator's knowledge of the system. It is generally very difficult to reconstruct using analytic tools what the "best" voltage profile should be on its system. For example, CONVEX schedules its voltage support to maintain a scheduled voltage on all regulated busses typically this results in a voltage of 1.035 $p.u$, or 357 kV. In an emergency the highest voltage allowed is 362 kV. The maximum limit is primarily related to operating problems of individual hardware (such as problems with surge arresters at excessively high voltages) and are not result of system studies. Within these limits, voltage is otherwise scheduled to minimize real power losses, resulting in as high as possible voltage.[7] In CONVEX, the same scheduled voltage is maintained for all load levels. REMVEC, on the other hand, has different peak and off peak voltage schedules; because of these two different operating practices in setting voltages, to compensate for transmission line (transmission cable) charging, CONVEX may ship some Vars to REMVEC at night, and may receive some Vars from REMVEC during the day.

Operators do not rely on real-time capacitor switching for boosting voltage to the minimum acceptable level after a contingency.

IV. Engineering solutions

Several preventive actions are taken by the CONVEX engineers in order to compensate for the loss of generating units. These measures can be classified into two general categories: the ones critical for supplying necessary real power and the ones critical for reactive power compensation and voltage support. In this section, we briefly review these measures. While only voltage-related issues are of prime concern in this paper, the real power problems impose equally important limitations.

A. Real power-related preventive solutions

In addition to the real power import, four 40 MW generating units were added at Devon and one 40 MW generating unit was added at South Meadow to improve the supply to Connecticut load. In addition, two retired units,

[7]Experience has shown that, because of meter accuracy problems and other operational considerations, it is necessary to have the scheduled voltage a little lower than the maximum allowable voltage.

located in Bridgeport Harbor and Middletown, were restored and made available for dispatch.[8]

Even with the newly installed capacitors there is a limit to how much power can be imported into Connecticut. Beyond this limit any additional demand can be met by opening several lines, thereby transferring some demand in Northern Connecticut to the system in Massachusetts [8]. This load is not part of the Connecticut as long as the system is operate with the temporary switching arrangement. The operating limits are based on the contingency that causes the largest voltage drop. (The thermal limits are calculated separately and they may be higher or lower than the voltage limits.) Should any critical facility be forced out of service, the transfer limits are appropriately reduced.

B. Voltage-related preventive solutions

The import from New York into Connecticut is limited by potential voltage problems. At around 300 MW import, Connecticut must send around 80 MVars back into New York. At around 900 MW real power import into Connecticut from New York the reactive power loss is approximately 130 MVars. Under certain operating conditions with one or more crucial lines trip, voltage may go below 330 kV unless dynamic reactive power support is provided. Large capacitor banks are, thus, installed at several critical locations throughout Connecticut to support increased real power import into the area. The reactive power is exported to keep the voltage from falling below operationally acceptable limits.

With these newly implemented capacitor banks and the strict enforcement of the import limits, the system meets the $(N-1)$ contingency criterion for all including the most critical contingency listed as contingency number 1 above, that is Long Mountain stuck breaker. Locations at which these capacitors are implemented are listed in TABLE I.[9]

It is interesting to analyze the decision making process which has led to these preventive actions. First, assessment of severity of voltage problem is made by executing numerous load flow simulations with several different scenarios. Since the results of a load flow program is not a systematic computing tool for determining corrective actions, experienced system planners are needed to estimate the overall effect of each simulation result and suggest possible preventive actions to be taken. The load flow is then used to analyze the effects of the suggested measures. This is repeated many times by trial and error prior to arriving at an acceptable set of preventive actions. In TABLE III such capacitor banks installation sites are shown for the contingencies of interest in this paper. With the number of different sites listed in the table, literally several thousand load flow simulations have to be performed before accurate conclusion can be reached based solely on the simulations. Engineers familiar with the voltage performance of the system are needed to obtain meaningful results in a reasonable amount of time, without running every combination of conditions.

TABLE I
New Capacitors implemented in New England in 1997

New Implementation			
substation name	# of caps	size (MVar)	total (MVar)
Manchester	3	52.4	157.2
Southington B	3	52.4	157.2
Frost Bridge	1	52.4	52.4
Glenbrook	1	39.6	39.6
Darien	1	39.6	39.6
Waterside	1	39.6	39.6
Montville	2	52.4	104.8
North Bloomfield	1	52.4	52.4
Agawam	2	52.4	104.8

Upgrades from 39.6 to 52.4 MVar		
substation name	# of caps	total increase (MVar)
Manchester	2	25.6
Frost Bridge	3	38.4
North Bloomfield	2	25.6
total capacity increase		837.2

V. Analytic solutions

A. Proposed Approach

In this section, we briefly describe the Steady State Voltage Monitoring and Control (SSVMC) method used to evaluate the voltage problems and propose corrective control actions for each given problem.

The method was first introduced by Ilić and Stobart in 1990 [4] and further developed for large systems by Ilić and Zobian in 1995 [6]. By considering sufficient conditions for existence of the unique solution to the decoupled nonlinear reactive power/voltage (Q-V) load flow problem, the SSVMC method quantifies the severity of a voltage problem by computing a "deviation vector" (D-vector); D-vector is computed for a given set of system changes/contingencies, i.e. load changes, generator failures, transmission line outages, etc of interest. Once the problem assessment is made, the smallest number of control actions is computed which are necessary for returning the voltage to pre-system change/contingency level. The choice is made from the set of feasible corrective actions specified by a system operator. A flow chart illustrating this method is given in Fig. 2. For details of this method, see [6].

[8]As of July, 1998 the unit at South Meadow and the unit at Bridgeport Harbor have been removed from service.

[9]Names for capacitor locations given in the paper refer to 115 kVbus of respective substations comprised of buses of several voltage levels. Southington A and Southington B are used to differentiate two 115 kV buses at Southington substation. In addition, we use Southington 345 kV to refer to the 345 kV bus at the same substation.

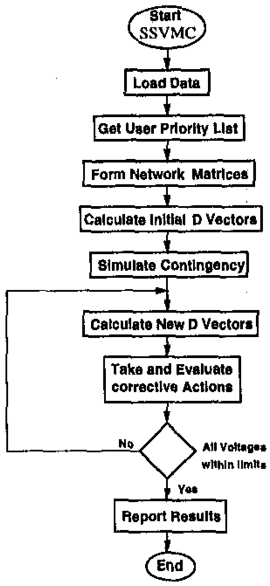

Fig. 2. Flow chart of SSVMC algorithm

B. Simulation Results

The data for SSVMC analysis are provided by the Northeast Utilities Service Co. The New England and the rest of the system[10] are represented as a system comprising 5983 buses, 1273 of which are generator units, and 6545 transmission lines. The generation and consumption patterns are that of typical summer peak operation. The following steps are taken to evaluate effect of taking four nuclear generation units out of service.

First, a desired target voltage is computed. The target voltage is the nominal voltage to be maintained by means of voltage regulation as system operating conditions vary. In computing target voltage we assume that all generating units (including four nuclear units to be taken out of service) and all system equipment is in full service with exception of capacitor banks listed in TABLE III. Each capacitor in the table is assumed to be a switching capacitor bank that is currently at off state but can be turned on whenever desired under the occurrence of certain contingencies in order to return the voltage to the target voltage after contingencies.

Then, the effect of four nuclear generators to be taken out of service is simulated as an contingency. The SSVMC method calculates the D-vector after the contingency by comparing the estimated voltage profile after the contingency with the target voltage. A feature of the method is that voltage profile can be estimated even when no load flow solution exists after the contingency and the recommended capacitor switching.

Finally, the SSVMC method determines the number and location of capacitors from TABLE III to be switched on in order to regulate the post-contingency voltage to the target voltage within desired accuracy. In practice, the installation of capacitors on a power system is constrained by a number of factors. For instance, the proposed site must have enough space. Also, for a number of contingencies and system configurations absolute voltage level and voltage flicker limits must be met.

[10]The part of the system further away from NE is represented in less details.

Due to the nature of reactive power support, the localized echelons-based approach is used [5], [6]. Using this approach, the SSVMC method calculates the network matrix and evaluates the optimal control actions only for the portions of system that exhibit voltage problems without considering the entire system. Since this calculation only requires the inversion of relatively small size matrix, the complexity of the system being evaluated has virtually no effect on computation time. This feature enables the method to be applied in near real time.

TABLE II summarizes the result of SSVMC analysis. With four generators taken out of service, voltage at Millstone 345 kV substation suffers the most severe deviation from the target voltage indicated by -9.759454 D-vector. In this simulation, SSVMC allows for evaluating the effect of any feasible control actions at buses within 10 tiers from Millstone 345 kV bus. The number of effected tiers is not excessively high, that is the effects are localized [7]. Ten tiers include all buses in Connecticut and most of buses in Rhode Island, a few buses in Massachusetts and a very small portion of busses in New York. Looking at D-vector the system is expected to have low-voltage problem caused by deficit in reactive power support. Total of 906.2 MVar capacitors are suggested to be switched on (implemented) at 10 different locations. After applying these corrective actions, the deviation at Millstone 345 kV substation is shown to be reduced to acceptable -0.053641.

C. Contingency tests

Next, we apply the four designated contingencies, described in Section II, on the top of the four generator outages. The SSVMC method attempts to restore the system voltage near its target value and by implementing post-contingency control actions as necessary.

In Long Mountain stuck breaker scenario, SSVMC initially suggests switching on two more capacitors to support voltage in the western part of Connecticut: one 39.7 MVar capacitor at Norwalk substation and one 39.6 MVar capacitor at Bunker Hill. However, the effect of these capacitors is rather minimal without significantly improving voltage profile, and several undesirable changes to the system, as acknowledged by NU engineers, become necessary in order to allow this post-contingency switching, which leads to dismissal of the initial recommendation.

In the loss of the Ludlow to Manchester to North Bloomfield 345 kV circuit scenario, SSVMC suggests the same number of capacitors as TABLE II, but the two capacitors at Agawam substation located in Massachusetts

TABLE II

An alternative way to implement capacitors suggested by SSVMC

substation name	# of caps	size (MVar)	total (MVar)
Manchester	4	52.4	209.6
Southington A	3	52.4	157.2
Southington B	1	52.4	52.4
Frost Bridge	2	52.4	104.8
Glenbrook	2	39.6	79.2
Darien	1	39.6	39.6
Plumtree	1	39.8	39.8
Berkshire	2	39.6	79.2
Card	1	39.6	39.6
North Bloomfield	2	52.4	104.8
total capacity			906.2

		D
before corr.	value	-9.759454
	@ bus	Millstone 345 kV
after corr.	value	-0.053641
	@ bus	Millstone 345 kV

are chosen to be implemented instead of the ones at Berkshire substation. This is because when the Ludlow to Manchester 345 kV transmission line is not available, the direct connection for transfer reactive power added at Berkshire into Connecticut is lost. Berkshire is no longer being considered as an optimal location for reactive power compensation following the topological change. Thus, SSVMC picks up the two capacitors at Agawam substation, that have similar impact and electric distance, to be implemented. For the limiting conditions with the load transferred to Massachusetts, Agawam and North Bloomfield capacitors are not connected to Connecticut, except through the Ludlow-Manchester-North Bloomfield line. Then there is no difference between Agawam and Berkshire. However, for other contingencies, especially with high transfer from New York, voltages at Berkshire and/or Ludlow become a concern. SSVMC indicates this concern, which compares favorably with the analysis done by NU engineers.

No additional capacitors are needed in the both loss of the Card to Sherman Road 345 kV circuit and loss of the Long Mountain to Pleasant Valley 345 kV transmission line cases. Computation of D-vector shows that in these cases, the voltage remains within acceptable range without additional capacitors being switched on other than ones listed in TABLE II.[11]

VI. Comparison of the Engineering and Theoretical Results

[11] Potential high voltage from loss of the Long Mountain to Pleasant Valley line is not considered in applying SSVMC method by the software in its present form.

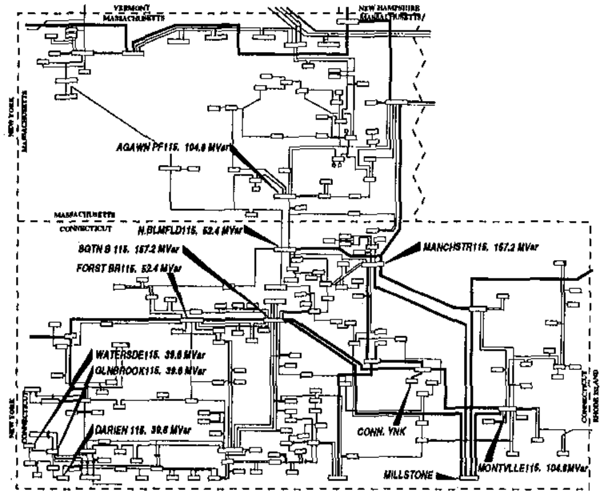

Fig. 3. A one-line diagram indicating the geographic locations of the capacitors implemented by CONVEX in 1997

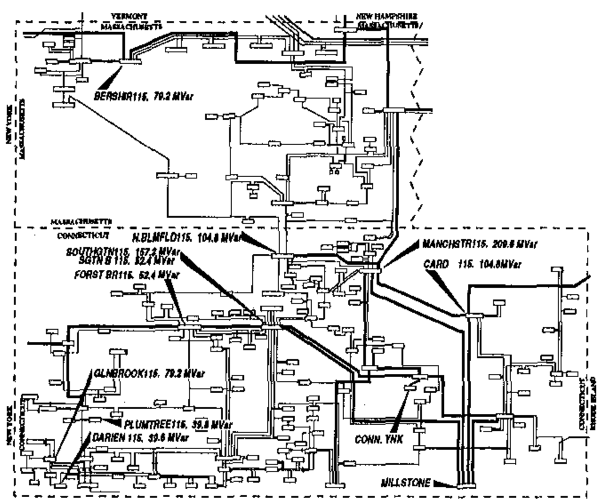

Fig. 4. A one-line diagram indicating the geographic locations of implementing capacitors suggested by SSVMC program

Fig. 3 and 4 are one-line diagrams that show the geographic locations of the capacitors implemented by NU and the locations suggested by SSVMC program, respectively. As illustrated in these figures, most of the locations are considered to be optimum both by SSVMC analysis and through the analysis done by NU engineers. Note that there are two 115 kV buses at Southington, Southington A and Southington B. They can be viewed as being the same location since they are both connected to the same 345 kV bus, Southington 345 kV bus.

At following four locations: Manchester, Glenbrook, North Bloomfield and Southington, one more capacitor bank than the currently implemented is suggested by SSVMC. At Manchester the suggested number of capacitors by SSVMC method agrees with an extensive study originally carried out by NU engineers. However, physical limitation allows the maximum of 6 capacitors (including the 3 capacitors existed before 1997) at the location as currently implemented although with 6 banks of totaling 314.4 MVar there are very heavy flows through the autotransformers at Manchester as well documented by SSVMC method. An extra capacitor suggested by SSVMC at Glenbrook offsets the effect of capacitor implemented by NU at Waterside. The reason for additional capacitors at North Bloomfield and at Southington is described later in the section related to different voltage regulation criteria.

Also, there are some differences between the two solutions regarding locations for adding new capacitors. In southwestern Connecticut, adding an extra 39.8 MVar capacitor at Plumtree is suggested by SSVMC to improve the low voltage situation in the Norwalk-Stamford area. In eastern Connecticut, SSVMC suggests adding capacitors at Card rather than at Montville. Since both buses are located at the second tier from the troubled bus, Millstone 345 kV, as shown in TABLE III, and their 345 kV substations are directly connected with Millstone through 345 kV transmission lines, the effects of these two locations are considered similar. In actual operations, the Montville capacitors may be more useful because Montville is closer to Millstone measured in terms of electrical distances whereas Card may have an advantage, since it is a termination point of a tie-line. In Massachusetts area, Berkshire rather than Agawam is selected by SSVMC program to implement two capacitor banks. Berkshire is two tiers closer and connected to Millstone 345 kV bus via 345 kV lines; therefore, Berkshire is considered a more effective location than Agawam. In addition, as discussed in Section V, Berkshire capacitors are more helpful with the power transfer from New York.

Comparing TABLE I and II, SSVMC suggests 69.0 MVar more capacity than the currently implemented one. Since SSVMC provides the optimal solution for specific contingencies, it suggests any corrective actions as long as it improves the system voltage profile. However, NU engineers apply a particular corrective action to that system only if it is necessary. In addition, SSVMC attempts to restore voltages to their pre-contingency voltages; therefore, it will target on the bus voltages before the contingencies happen even if the voltages may be already at acceptable values. On the other hand, NU engineers only attempt to improve system voltages back within an acceptable range since they have sufficient experience and knowledge to justify a "good-enough" voltage profile that does not cause operating problems.

To minimize costs NU installs capacitors in groups of three banks whenever practical, for example, at Manchester and Southington B, because the three capacitor banks are protected by one circuit breaker and are individually switched by circuit switchers. When only one or two banks are installed, a circuit breaker is relative costly. Such economic concerns are not implemented in the current SSVMC analysis.

As demonstrated in this section, even though the NU engineers' and MIT's solutions are based on two different methodologies, the end results are similar to each other; within 4 % or 69.0 MVar difference in term of total capacitor support. This not only shows that the solution applied by NU engineers is theoretically justifiable but also verifies that SSVMC program is able to diagnose the impact of contingencies and suggest suitable corrective actions to alleviate the voltage related problems.

VII. Conclusions

In this paper we have analyzed potential voltage problems in the Connecticut area of the New England power systems. Four critical contingencies are evaluated. Preventive measures taken by the engineers for avoiding service interruptions are described. These amount to importing power and re-configuring several lines to supply part of CONVEX load by the NE power plants outside of Connecticut. As real power imports take place, increase in reactive losses could lead to unacceptably low voltages. To prevent this from happening, several capacitors banks were installed and they are switched on in anticipation of possible contingency events that require them to maintain adequate system voltage.

To arrive at a good understanding of potential problems and to identify best sites and size of the installed capacitors, the engineers have had to perform a large number of load flow studies off line. Additional operating studies are needed to determine the limits with the capacitors available.

In this paper we suggest that operating could be provided in an on-line setting; as the SCADA data gets updated each 15 minutes or so, it is possible to use an analytically-based method to compute remedial actions necessary to maintain voltages as close to their nominal values as possible with the available resources. This requires continuous tuning of set points for voltage regulators on generators, as well as switching of capacitor banks and adjusting tap-changing transformers. Moreover, as the system is screened for critical contingencies, one should take into consideration the stand-by reactive power/voltage support which can be activated to prevent the contingency from becoming critical. In other words, if software is available for fast prediction of system conditions following a specific contingency of interest and for determining an effective combination of remedial actions, it is possible to provide near real-time voltage regulation for many contingencies presently considered as limiting without these remedial actions. The software described in this paper is useful for this purpose. Its verification is provided by comparing the results obtained by extensive off line studies.

An automated closed-loop generation-based voltage regulation has been a routine practice in France and Italy for more than a decade now. The software proposed here is not based on reduced information (pilot point bus only). Instead, full SCADA information is used for implementing all available, generation-based and network switching control mechanisms in order to maintain all voltages close to their desired, normal, values as system conditions change.

It is easily shown that by relaxing the steady state voltage limits set by contingencies previously thought of as critical, the system can be operated more economically than without these on-line remedial actions.

APPENDIX
POTENTIAL CAPACITOR INSTALLATION SITES

TABLE III
Potential Capacitor Installation Sites

substation name	Max number	Size (MVar)	Tier number
Manchester	6	52.4	2
Southington A	3	52.4	2
Southington B	3	52.4	2
Montville	3	52.4	2
Card	1	39.6	2
Frost Bridge	3	52.4	3
Berlin	3	39.8	3
Barbour Hill.	1	39.6	3
North Haven	1	42.0	4
Devon	3	52.4	4
Campville	1	39.6	4
Ludlow	3	52.4	4
East Shore	3	42.0	5
Plumtree	3	39.8	5
Bunker Hill	1	39.6	5
Sackett	1	42.0	6
Berkshire	2	39.6	6
Haddam	1	39.6	7
Norwalk	2	39.7	7
Darien	1	39.6	8
North Bloomfield	3	52.4	8
Agawam	2	52.4	8
Glenbrook	4	37.8	9
	2	39.6	9
Waterside	1	39.6	10

VIII. REFERENCES

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