Dynamic Voltage Stability Reserve Studies For Deregulated Environment

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Abstract: **This paper first analyzes why voltage instability occurs in mature yet competitive power systems, and then investigate diverse voltage stability issues in deregulated power markets using a commercial transient simulation program EUROSTAG. Dynamic behaviors of major power system components, i.e., speed governor, excitation element, inductive motor, ULTC and mechanically switched shunt capacitor et al, are thoroughly examined by a small yet typical equivalent system. The presented simulation results help better understand the mechanism of the voltage collapse phenomena, and highlight the importance of dynamic reactive reserves, like generators, in dynamic voltage stability enhancement.**

Index Terms: **Dynamics, reactive power capability, time domain simulation, voltage stability**,

I. INTRODUCTION

IN the past decades, voltage stability became a major concern in the North American power systems, to a large extent due to more intensive use of available transmission facilities. It has been noted that unbundling of generation and transmission services potentially reduces voltage security margins of the power systems because:

- To reduce the capital investment cost, the generation companies prefer buying those generators with lower reactive support capability, since they have a higher benefit-to-cost ratio per MW generation capacity.
- To minimize their reactive power payments, the buyers install excessive shunt capacitor banks at the load buses, to avoid the use of the more expensive dynamic reactive resources, like generators, condensers, SVCs, etc.
- Due to the lack of the system-wide reactive power resource planning, the strength of the system to withhold the voltage instability incidence is location-dependent, since dynamic reactive reserves of the system are unevenly distributed.
- Reactive power losses in the transmission grids are rising, due to increased energy transfer levels among intra-zones and inter-zones.
- As the total transmission capability (TTC) in main transmission paths is enhanced by means of FACTs devices, the reactive power transfer capability of these transmission paths remains limited.

Consequently, quite a few utilities and power pools have suffered from voltage instability incidences; some of them evolved into a voltage collapses in the 1990s [1].

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To prevent voltage collapse occurrence, various steady state computation tools are established to detect the so-called voltage collapse point (i.e., saddle-node bifurcation) from a given initial operating condition. Several famous static analysis approaches are summarized below: (i) multiple power flow solutions [2]. (ii) Continuation power flow (CPF) [3]. The CPF traces the singularity of the steady state load flow Jacobian by a locally parameterized continuation technique. (iii) Point of collapse approach (PoC) [4]. (iv) Sensitivity analysis [5][6], such as $\Delta Qg/ \Delta Qd$, $\Delta Vd/ \Delta Qd$, $\Delta Qg/ \Delta Vd$, and modal voltage variation et al static indices, which are derived from the full or reduced power flow Jacobian matrix. The static evaluation tools demonstrate sufficient potentials for on-line implementation. Nevertheless, their accuracy and effectiveness on the practical power systems may not be reliable enough, due to the inability to exactly model some dynamic responding elements, like governor, voltage regulator (AVR), under load tap change (ULTC) transformer and inductive motor load etc [7]. It is recognized that dynamics of electrical elements has significant influence on voltage collapse evolution of a power system [8].

Recently, features and modeling capabilities of commercial transient stability time domain simulation programs, i.e., EMTP, PSS/E, NETOMAC and EUROSTAG et al, have been greatly enhanced to make them suitable for the assessment of various voltage stability problems. In effect, these sophisticated simulation programs have enabled the users or researchers to construct very realistic voltage collapse cases of interest in an off-line environment, thus facilitate them to better understand complex voltage instability phenomena. In this paper, we utilize EUROSTAG to investigate the voltage stability problems under open access via a small yet actual power system. As a time domain simulation program, EUROSTAG is well equipped for detailed and accurate study of the transients, associated with mid-term and log-term phenomena in large power systems. The program contains a set of standard models: full IEEE library, relay and automation devices and main FACTS components.

Our interests focus on dynamic reactive reserve issues for voltage stability in a deregulated electricity market. Such as:

1. The effects of reactive power support of generators. Is it local or system-wide under certain disturbances?
2. Is the use of ULTC beneficial or detrimental to voltage stability?
3. Can switched shunt capacitor banks at load buses be a reasonable replacement for dynamic VAR reserves?

4. The influence of the increased power transfer on the voltage collapse.
5. The validity of the steady state analysis approaches on providing an accurate estimation for the voltage collapse point.

   And so on.

The paper is organized as follows: modeling of a typical test system is described in the next section. A variety of dynamic simulations on voltage instability incidences are introduced in section III, together with interesting simulation curves and in-depth result analysis. Finally, several new viewpoints about the voltage stability problem are discussed upon dynamic simulation results.

II. TEST SYSTEM DESCRIPTION

The used test system contains a variety of major components: generators equipped with speed governor and voltage regulator (AVR), inductive motors and static loads, step-up transformers with fixed turn ratios, ULTC transformers at load buses, shunt capacitor banks, and five parallel long-distance 500 KV transmission lines. The network structure of the test system is shown in Figure 1, including main steady state data. Complete data for steady state power flow calculation are given in Appendix E of [1]. Dynamic modeling of major elements is as follows.

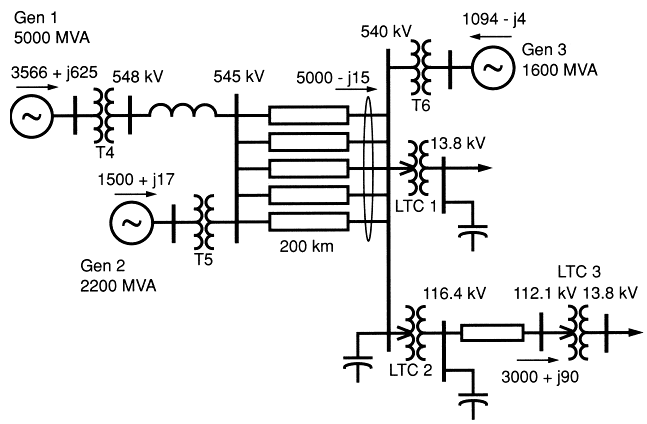

Fig.1. Diagram of the test system

A. Generator Modeling

Three generators have identical dynamic characteristics, corresponding to a 0.95 power factor, 590 MVA coal-fired unit. The inertia constant, *H*, for Gen 2 and Gen 3 is 2.32 MW-s/MVA. Gen 1 is an equivalent of a large interconnection with *H=15 MW-s/MVA*. The MVA rating and base case generations are given in Figure 1. Both block diagrams of governor and voltage regulator are cited from Unit *F18* in [9], where particular electrical parameters are listed in Table I and II respectively.

Table I. Parameter assignments of Governor –Type G

K	T1	T2	Pmax	T3	T4	T5	α
20	0.08	0	1.05	0.15	0.05	10	0.28

Table II. Parameter assignments of Excitation System –Type G

K_A	T_A	T_B	T_C	K_F	T_F	V_{Rmax}	V_{Rmin}
200	0.3575	0	1	0.0529	1	2.5	-2.5

According to Table 2, the maximum reactive capability is as follows, associated with initial set points of three generators.

Gen 1: V =13.53 KV, slack bus
Gen 2: V =13.3 KV, -200MVAr ≤ Q_G ≤ 735 MVAr
Gen 3: V =13.4 KV, -250MVAr ≤ Q_G ≤ 1000 MVAr

B. Load Pattern

The entire system contains one industrial load of 3000 MW +j 1800 MVA*r*, and another 3000 MW residential & commercial (R&C) load. The former is supplied with LTC1, including two inductive motors: a 3375 MVA large motor consumes 2700 MW, while a 500 MVA small motor consumes the rest 300 MW. Specific data in Table III and IV corresponds to these two motors. The 3000 MW R&C load is supplied with LTC3, and is represented by static load characteristics: 50% constant power and 50% constant impedance.

Table III. Dynamic characteristics of small industrial motor

Rs	Xs	Xm	Rr	Xr	A	B	H	LFm
.031	.10	3.2	.018	.18	1.0	0	0.7	0.6

Table IV. Dynamic characteristics of large industrial motor

Rs	Xs	Xm	Rr	Xr	A	B	H	LFm
.013	.067	3.8	.009	.17	1.0	0	0.8	0.7

C. ULTC Transformer Modeling

Transformer ULTC actions are represented with time delays and deadbands. Time delays for ULTC operations are assumed to be 30 seconds for the first tap movement and 5 seconds for subsequent tap movements. The bandwidth is assumed to be ±0.00833 p.u corresponding to 2 volts on a 120 Volt base. Of three ULTC transformers, LTC2 is purposely blocked during the simulation. Tap of LTC1 is allowed to range from 500 KV over 550 KV at discrete ±16 steps. Tap of LTC3 is allowed to range from 103.5 KV through 126.5 KV at discrete ±16 steps. Voltage set points of both ULTCs are automatically computed in the simulation.

D. Switched Capacitor Bank Modeling

Three groups of capacitor banks are installed in the test system. Bank 1 is connected to the industrial load bus, with 15× 100 MVAr nominal output. Bank 2 is installed at the receiving end of 500 KV lines, with 10 × 86.8 MVAr nominal output. Bank 3 is installed at the lower voltage side of LTC3, with 6× 50 MVAr nominal output.

III. DYNAMIC SIMULATION CASES

A. Detection of the dynamic voltage collapse point

We first examine a longer-term voltage collapse phenomena, which is trigger by a 500-KV line outage and the follow up load rising disturbance. Simulation events are set up as follows,

I. At 0.0s, start with a base case operating point
II. At 20.0s, a 500-KV line outage occurs.
III. At 100s, a load disturbance with a rising rate of 3 MW/per sec. is imposed onto the R&C load bus.
IV. The simulation evolves until 500s, or until the system voltage collapses.

The overall simulation time takes about 251.6 sec. to encounter a voltage collapse, where the integration algorithm is failed due to the singularity of the Jacobian matrix. It should be pointed out that the increased load 454.8 MW, i.e., (251.6-100)×3 MW, does not really reflect actual voltage stability margin of the test system, considering that the system state keeps evolving towards next operating points after the disturbance is removed. To find the actual collapse point, we need to check a range of simulation cases that different load disturbance durations are assumed. The selected typical cases are

Case A: the disturbance duration is 100s through 200s.
Case B: the disturbance duration is 100s through 225s.
Case C: the disturbance duration is 100s through 246.5s.
Case D: the disturbance duration is 100s through 247s.

Then repeat the previous simulation procedure for each of four cases. Checking various simulation results, we find

Case A, B and C all survive from a voltage collapse. In particular, after the load disturbance, Post-disturbance bus voltages of the system are restored to near the pre-disturbance level in Case A; the post-disturbance load bus voltage in Case B is maintained only above the required lower limit (i.e., 0.95 pu), while one local generator Gen3 is converted into a PQ bus due to its excitation upper limit enforced. The post-disturbance load bus voltage of Case C further drops to 0.90 pu, but dose not fall into a voltage collapse. In Case D, the system voltage collapses around 256.8s, shown in Fig.2. Note that the rapid load rising does not cause a loss of synchronism in this case. The maximum frequency drop is only about -0.4%. In comparison to Case 3 and 4, we conclude that the estimate of the maximum load increase under the given disturbance is 439.5 MW, i.e., (246.5-100)×3 MW. It reflects dynamic voltage stability margin of the system under certain contingencies.

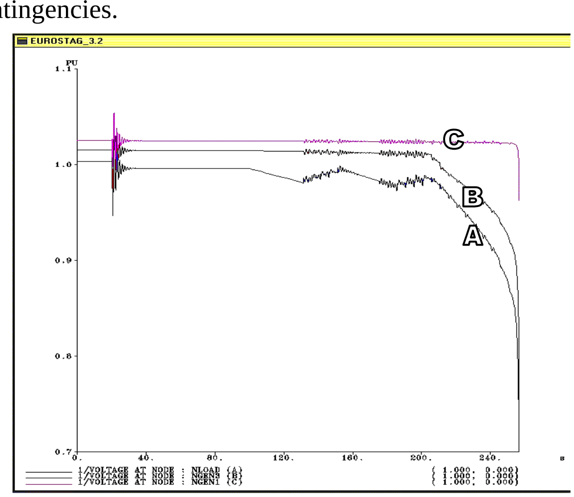

Fig.2. Bus voltage profiles in Case D

B. Dynamic Behaviors of Major Elements Over Voltage Collapse

In the next, we examine dynamic behaviors of governor, excitation system (voltage regulator), ULTC, shunt capacitor et al major primary components from the imitated voltage collapse incidence (Case D). From the observed dynamic behaviors, we will approve or disapprove some myths about the voltage stability problem.

1) Myth 1: Reactive power support of the generator with voltage regulator is local in nature, and reactive power reserve strength of the local generator sounds a straightforward indicator for the proximity to a voltage collapse.

Reactive power generation variations of three generators under the assumed disturbance are plotted in Fig.3.

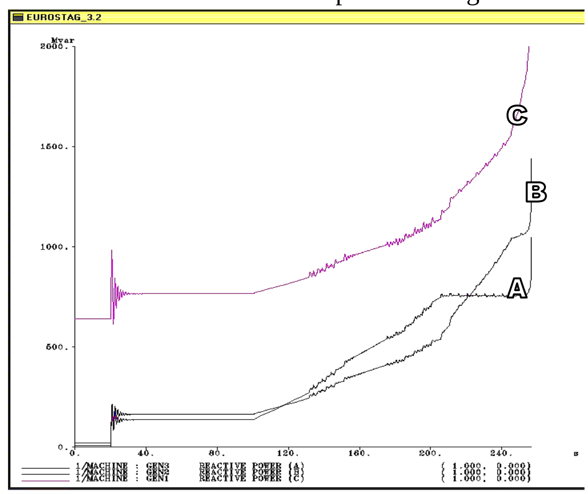

Fig.3. Reactive generation variations in Case D

Prior to the disturbance, only Gen 1 generates a certain amount of reactive power to support the system voltage profile, while the other two units are operated on a power factor of unity, i.e., maximum reactive capability reserves. Since the disturbance, both local generator: Gen 3 (curve A) and two remote generators: Gen 1 (curve C) and Gen 2 (curve B) have been timely increasing their reactive support to prevent system voltage decaying until Gen 3 and Gen 2 hit their reactive capability limits successively. It is noted that after the local generator reaches the reactive upper boundary (735 MVAr), it takes additional 40s simulation evolution or 120 MW load rising, to cause the voltage collapse. It is found that a local PV bus switches to a PQ bus during the disturbance may not imply an immediate voltage collapse.

The underlying Fig.4 illustrates reactive power flow at the receiving end (curve B), average reactive flow (curve C) and reactive loss (curve A) variations in the single 500KV line. It reveals that the transmission network consumes much reactive power so that the increased VAR supply of two remote generators fails to enter the load area. Evidently, increased reactive support of Gen 2 and Gen 3 is crucial for extending the voltage stability margin of the system under the disturbance. It enforces that voltage control of generators has system-wide functionality, not a local nature of reactive delivery as many people claimed. Accordingly, individual electricity buyers or customers should pay both explicit reactive power delivery (load) cost, and implicit dynamic reactive reserves cost for potential voltage security benefits.

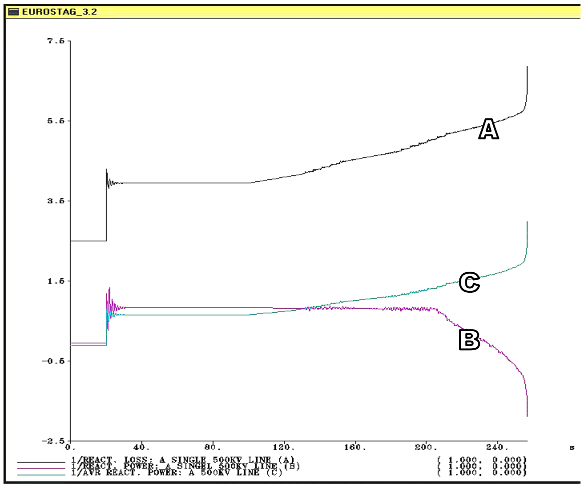

Fig.4. Reactive flow and loss variations in a 500 KV line

2) Myth 2: The use of ULTC transformers purposes to boost up voltage magnitudes of the installed load buses under various small disturbances, hence ULTC is also beneficial to the voltage stability of the system.

Tap change variations of LTC1 and LTC3 are plotted in Fig.5. EFD response characteristics of excitation system are shown in Fig.6.

To compare Fig.6 with Fig.7, we notice that the EFD variations correspond to dynamics of ULTC during the simulation. More or less, ULTC actions affect the EFD as a line outage. When LTC1 and LTC3 are blocked during the simulation, the solved load evolution time is extended to about 268s (see Fig.7.). Compared to the previous Case D, deactivation of ULTC devices has increased real power transfer by 63 MW, a 14.33% improvement.

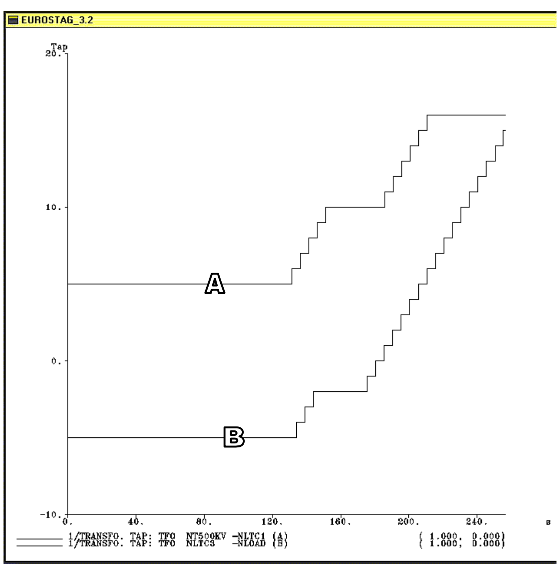

Fig.5. Tap changes of LTC1 and LTC3 in Case D

It indicates that ULTC utilization actually shrinks voltage stability margins of the test system, though ensuring voltage quality of the regulated nodes. In cases of long-term voltage collapse, side effects of ULTC can be compromised when the regulated node is installed with capacitor banks. One wiser choice is to have ULTC devices blocked temporarily upon any warning of the voltage instability. However, it is an interesting issue to choose appropriate timing to block/de-block ULTC devices in the real-time operation environment.

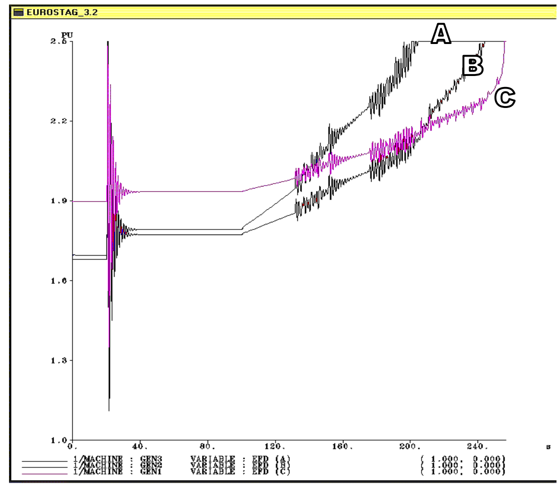

Fig.6. EFD variation curves in Case D

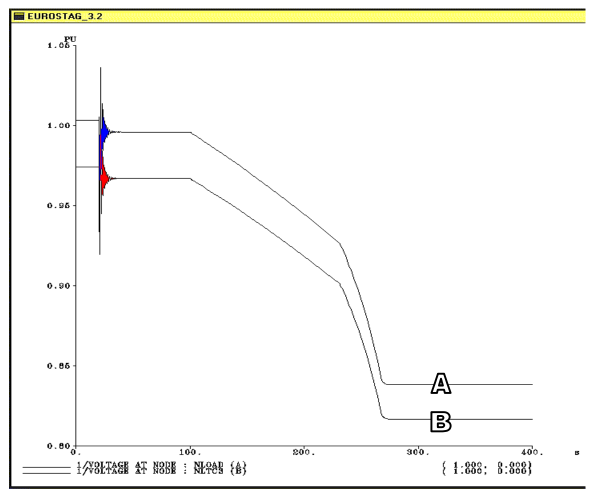

Fig.7. Load bus voltage variations with ULTC off

3) Myth 3: Mechanically switched shunt capacitors can be a reasonable replacement for dynamic reactive sources, such as synchronizing generator, condensers and SVC.

In the recent decade, many customers have installed fixed or switched shunt capacitor banks themselves to compensate the local reactive loads, and to support local bus voltages. Instinctively, these customers are reluctant to pay extra reactive power support costs to the owners of generators or other dynamic reactive resources. However, as a type of heavily voltage-dependent element, dynamic response of shunt capacitors is quite passive under the disturbance [see Fig.8]. In effect, excessive use of shunt capacitors aggravates imbalance of reactive power under certain disturbances, and becomes one cause of voltage collapse incidence.

Now, we consider utilizing extra switched capacitor banks to replace dynamic reactive reserves of the generators. Particularly, Bank 2 is equipped with 3× 86.8 MVAr new banks. Bank 3 is equipped with 3× 50 MVAr new banks. New banks are assumed to timely switch on whenever the connected bus voltage is below 0.95 pu, with no delay. In the meanwhile, the EFD of Gen 3 is reduced to 2.0 pu, i.e., a loss of 400 MVAr reactive power capabilities. To simulate the same events as Case D, we find a new voltage collapse point, where the maximum power transfer is reduced to 366 MW (i.e., evolution load disturbance ends at 222s), compared to the base case 439.5MW. The simulation results are reflected in Fig.9 and Fig.10. Since the shunt bank requires a few minutes for charging operation before switching on, associated with over a few seconds for mechanical action, the actual performance of switched capacitor banks will be further discounted compared to the simulation result. As for the short voltage collapse (say a few seconds), switched capacitor banks have little effect due to slow response time. For either case, dynamic reactive reserves appear as the most reliable means for voltage stability enhancement.

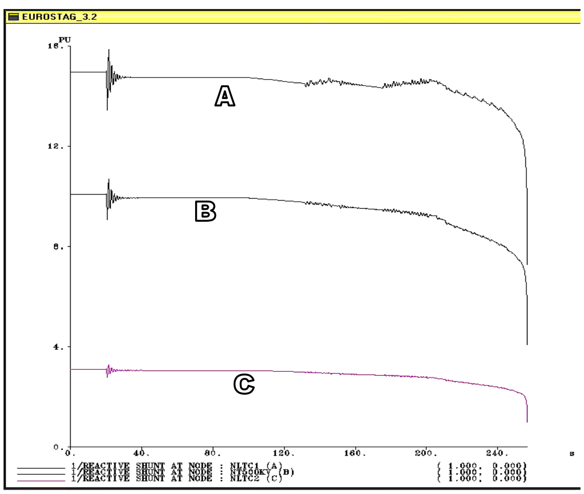

Fig.8. Shunt capacitor reactive power variations in Case D

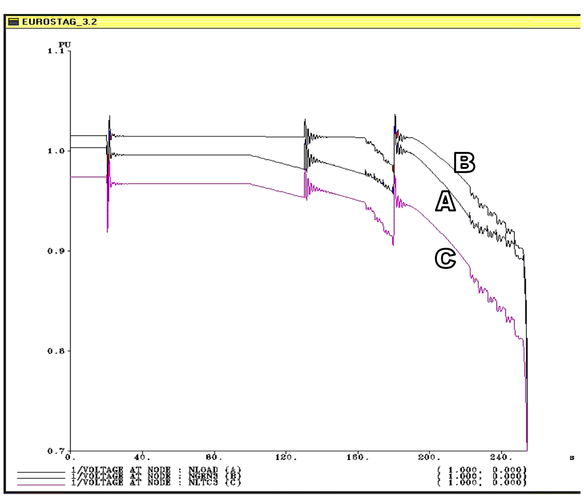

Fig.9. Load bus voltage variations with switched banks

It is also noted that the switching of shunt capacitor banks can cause serious harmonics in bus voltage, hence affect power quality on the demand side.

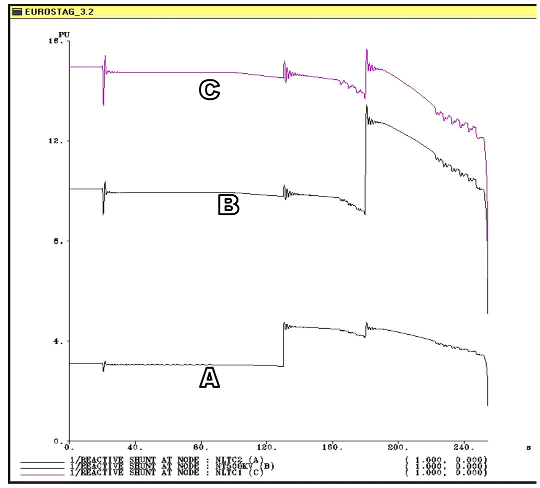

Fig.10. Switched shunt capacitor output variations

4) Myth 4: Compared with reactive power loads and their characteristics, real power loads have little to do with voltage stability.

In the past, many works on the voltage stability problem, especially some sensitivity methods, concentrated on reactive load and its characteristics, and paid less attention to reactive losses resulting from the increased real power transfer. In the presented simulation cases, approximate 15% pure MW rising at a R&C load bus triggers a voltage collapse. This is because that the increased active power flow largely aggravates reactive losses in the occupied transmission paths. This indicates that inclusion of reactive losses is significant for the exactness to detect a voltage collapse point.

5) Myth 5: Steady state analysis approaches have sufficient accuracy to assess voltage stability margins under the selected disturbances.

In this paper, we employ steady state continuation power flow (CPF) to check the difference between a static voltage collapse point and a dynamic voltage collapse point upon the same disturbance. It is found that the CPF solved Pmax is near 500 MW, or 10+ % higher than the dynamic simulation result shown in Case D.

The resultant discrepancy is attributed to modeling of dynamic responding components. For examples, in the time domain simulation, when the system suffers a disturbance, the speed governor will timely respond to adjust active power generations without any interference [see Fig.11]. In the CPF, the rate of change in generation is beforehand specified by users. Besides, the CPF is unable to model dynamic load characteristics, like inductive motor, but the time domain simulation can exactly model both static and dynamic loads. Most important, time response characteristics of reactive support capability of the generators fails to be precisely modeled in the steady state analysis, which simply deals with a generation bus by either PV or PQ bus.

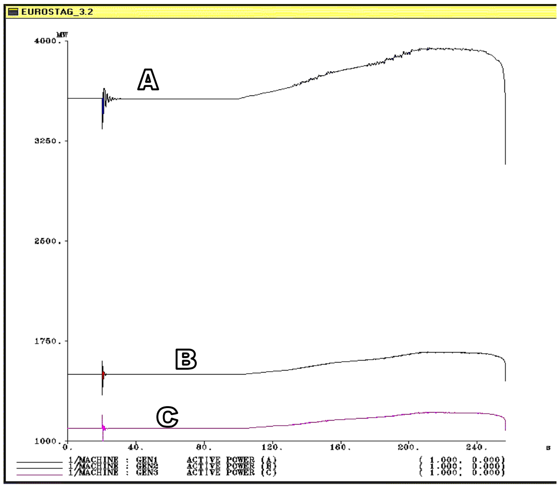

Fig.11. Speed governor response variations in Case D

IV. CONCLUSION

The advanced time-domain simulations provide a realistic picture about voltage collapse phenomena. Under a major disturbance, dramatic power flow variations lead to rapid rising of reactive losses. As dynamic VAR reserves do not timely compensate the increased reactive loss, the system voltage will have a serious decay. As a consequence, the line charging and shunt capacitor injections decrease dramatically, and further aggravates reactive power imbalance of the system. Subsequently, bus voltage magnitudes continue to drop until a voltage collapse occurs. From the above voltage collapse studies, we have the following findings:

- Rapid rising of reactive losses due to the disturbance is a major factor to trigger a voltage collapse. Reactive power losses are decided by both bus voltage magnitudes and branch currents. Reactive power dominates bus voltage magnitudes while real power contributes to the majority of branch currents. Therefore, both real and reactive power has important impacts on the voltage collapse.
- During voltage decay towards the voltage collapse point, all generators participate in matching reactive power imbalance throughout the entire system. Local generators mainly support reactive power loads, while the rest generators pick up the distributed reactive losses. For serious cases where the system reactive losses surpass the reactive loads, the generators nearby the heavy transmission lines may offer more reactive power support than the generators within the load center. It demonstrates that voltage control function of the generators is system-wide, not a local nature of reactive power delivery as many claimed.
- Conventional sensitivity methods are derived from reactive power characteristics in the system, and neglect effects of real power transferring. Our simulation results demonstrate that increased reactive losses in the transmission network consume most dynamic reactive reserves of the generators under the major disturbances. Since serial reactive power losses mainly come from energy deliveries, sensitivity methods are inaccurate for voltage collapse detection.
- Emergency reactive power exchange capability between neighboring areas is still very limited. A feasible solution is to utilize FACTS devices to change reactive transfer characteristics of the system. To strengthen the ability of the power system to withhold voltage instability, distributed dynamic reactive reserves must be considered in reactive power scheduling.
- To improve over-excitation limits of the generators is a critical means to hedge the power system against the voltage collapse initiated by an outage fault.
- Dynamic reactive reserves stored in generators, SVC and condensers are still the most effective and reliable means to prevent voltage collapse occurrence due to unanticipated contingencies, i.e., outage of major generator or transmission line, rapid load rising.
- The ability of switched shunt capacitor banks to respond emergency conditions is very limited, hence their values on voltage stability enhancement may not be overestimated.
- Since steady state analysis methods do not exactly follow dynamics of major electrical components, the solved static voltage stability margin is too optimistic in comparison to the dynamic simulation result. This potentially imposes major risks on planning and operation of the power systems.
- All the above observations have significant impacts on charging reactive services for real power transactions.

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VI. BIOGRAPHY

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