01 Nov 2000

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***Abstract*—Several analysis methods are available for long-term voltage stability. The V–Q curve power flow method is widely used by Western Systems Coordinating Council utilities, and has some advantages. Long-term dynamic simulation with proper modeling, however, is clearly the most accurate simulation method.**

We compare the two methods for wintertime voltage stability problems in the Portland, Oregon USA load area. Results from the V–Q method can be misleading. The same is true of other power flow program based analysis employing conventional modeling. Results from these power flow methods may be pessimistic, causing overdesign or overly conservative operation.

***Index Terms*—Long-term dynamic simulation, power flow simulation, voltage collapse, voltage stability.**

I. Voltage Stability Analysis

In RECENT years, voltage instability and collapse have limited power transfers and threatened power system reliability. Many analysis methods have been developed [1]–[3].

P–V and V–Q curve power flow program methods have been used for many years. Bonneville Power Administration (BPA) and other Western Systems Coordinating Council (WSCC) utilities mainly use V–Q methods, but the need for dynamic simulation is gradually being recognized. The V–Q methods are used for both planning and operation studies.

A. The V–Q Curve Method

The V–Q method was developed from difficulties in power flow program convergence of stressed cases close to the maximum power transfer on a path. Convergence was achieved by the trick of fixing the voltage at a critical bus. The amount of reactive power support from this fictitious synchronous generator (PV bus without reactive power limits) was noted. Other voltage magnitude values could be scheduled and the required reactive power support noted. (Other methods to achieve convergence include artificially increasing generator and SVC reactive power limits, and using voltage sensitive loads.) Dynamic simulation does not have the same convergence problems in part because loads are voltage sensitive, abet with load restoration controls.

Modern power flow programs, however, will converge close to the maximum power transfer value. Methods include full Newton algorithm and "nondivergence" techniques [4]. Reference [1, Appendix B] provides introductory description.

B. V–Q Curve Methodology

For a power flow base or outage case, power flows are simulated with a series of voltage magnitudes scheduled at a selected important bus. The selected bus is changed to a fictitious PV bus, equivalent to applying a fictitious synchronous condenser or SVC at the bus. The voltage magnitude scheduled is an independent (x) variable. The reactive power injection is a dependent (y) variable. (Q–V curves, similar to P–V curves are also possible where reactive power at one or many busses are independent variables, and voltages at many busses are dependent variables.)

A curve of bus voltage versus synchronous condenser output is thereby generated. The operating point is at zero MVAr output of the fictitious synchronous condenser unless reactive power compensation is available or planned for the bus.

The V–Q curve computation is automated in many power flow programs. The analysis may have to be applied to more than one bus.

C. Advantages of the V–Q Curve Method

The method offers considerable insight into voltage stability performance, and into reactive power compensation needs. Advantages include:

1) Convergence is normally not a problem, even on the "unstable" left side of the curve.
2) With automation of the series of cases, the method is fast. For a small change in the scheduled voltage, convergence takes only a few iterations with the conditions from the previous case used as the starting point.
3) Reactive power shunt compensation requirements are approximately given and reactive power compensation characteristics (capacitor bank or SVC) can be superimposed on the V–Q system characteristic.
4) The slope of the curve indicates voltage "stiffness."
5) Plots of reactive power output of generators and SVCs may be superimposed on the V–Q curve graph. Near the bottom of the curve, generators providing effective support will be at their limits. Generator reactive power and remaining reserve at the operating point may be noted.
6) The reactive power margin from the operating point to the critical point (bottom of curve) for the bus is directly provided. Since voltage stability and reactive power are closely related, this margin is used as a reliability index

Manuscript received July 19, 1999; revised April 20, 2000.

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Publisher Item Identifier S 0885-8950(00)10370-0.

or criterion. (In the cases described below, the bottom of the curve is above the bus capacitor bank characteristic, indicating negative margin and no operating point.)

D. Disadvantages of the V–Q Curve Method

There are enough disadvantages of the method that over reliance must be discouraged.

1) The method is artificial, involving stress at a single bus for local area evaluation [5]. (P–V power flow program methods, on the other hand, more realistically stress a power transfer path, allowing more global evaluation.)
2) V–Q curves at many busses may be required per contingency and per power level.
3) The allowable power loading or interface flow is not directly given.
4) V–Q curves indicate local compensation needs for a given operating condition rather than global optimal compensation needs.
5) Similar to other power flow based methods, simple generator and load models are generally used (e.g., constant power loads at high voltage busses). Also, the time-dependent aspects of control actions are not represented.

Items 2–4 suggest the method may be inefficient compared to other power flow based methods (P–V, binary search for transfer limit, or optimal power flow). Item 5 suggests accuracy concerns. The purpose of this paper is to demonstrate the inadequacy and inaccuracy by examples from large-scale simulation of a real power system. For a large power system, we compare simulation results between the V–Q curve simulation and benchmark dynamic simulation using more detailed models.

E. Dynamic Simulation

Dynamic simulation is the benchmark for verifying power flow based simulation results. Dynamic simulation accurately includes the time dependent actions of control and protection, and predicts the time available for operator actions. Modeling for long term dynamics include more detailed representation of loads such as bulk power delivery LTC transformers and feeder equivalents, voltage sensitive static loads, and dynamic loads. Overexcitation limiters and other generator controls are represented in detail. Switching of capacitor/reactor banks based on voltage and time delay settings are modeled correctly. In critical cases, corrective countermeasures such as capacitor/reactor bank switching must be fast enough to ensure attraction to the post-disturbance operating point [2].

Full dynamic simulation using transient stability models plus the longer-term models is time consuming. A good compromise between speed and accuracy is the fast dynamic (quasistatic) simulation technique [2]. Results shown below are from full dynamic simulation. However, comparable results were obtained using a prototype fast dynamic simulation program developed by Powertech Labs, Inc. for on-line voltage security assessment.

With dynamic simulation, stability margin is not directly computed. (Actually for highly voltage sensitive loads, and with limits on load restoration by tap changing, instability is unlikely.) In the simulations described below, we use post-disturbance steady-state generator reactive power reserves and bus voltage magnitudes to judge stability/security margin. Reactive power reserves at key generators and at SVCs are sensitive indicators of voltage security.

Fig. 1. Pacific Northwest 500-kV transmission network.

II. Portland Area Voltage Stability

Voltage instability and collapse is possible during heavy wintertime load conditions in the Pacific Northwest. Interrelated voltage stability problems exist in the Vancouver, B. C., Seattle, and Portland load areas [6]. Here we focus on outages affecting the Portland area. Fig. 1 shows the Pacific Northwest 500-kV transmission and major generating plants.

A. Base Power Flow Conditions

We used a January 1999 extra-heavy load base case corresponding to one-in-twenty year cold weather in the Pacific Northwest. The entire WSCC interconnection was represented (around 6000 busses).

B. Modeling for Power Flow and Dynamic Simulation

For V–Q curve power flow simulation, we followed methodology used for planning and operating decision making. Loads were represented as constant power at high voltage busses, typically 115-kV. Reference [1, Appendix C] describes the general procedure.

For dynamic simulation, we added around 750 bulk power delivery LTC transformers in the Pacific Northwest (e.g., 115–12.5-kV) Transformers were initialized at 5% above neutral tap with 5% boost regulating range. Since during extra-heavy load conditions only a few boost tap positions may remain prior to a disturbance, this regulating range is probably conservative from a load restoration and voltage stability viewpoint. As described below, some cases assumed a boost range of 10%.

Dynamic models included LTC transformer control, and overexcitation limiters (OELs) at John Day, Centralia, Bonneville, Boardman, and WNP-2. We used typical data for the tap changing transformers: 30 or 60 second time initial time delay, 5 second mechanism time, $\pm 10\%$ tap range with 32 steps of 5/8% each, and $\pm 0.83\%$ deadband corresponding to 2 volts on 120-volt base. We assumed 10% LTC transformer reactance on the load base, which captures much of the reactance from high voltage busses to loads.

The OELs modeled were of the summing type with soft limiting as opposed to the hard limiting imposed by takeover types. With the summing type, the normal voltage regulator loop is still retained [7]. A specific type of OEL provided by some manufacturers of excitation equipment allows excitation overload as an inverse function of time. The higher the overload, the shorter the time allowed for overexcitation. When the excitation reaches the limiter's instantaneous setting, typically about 160% of the rated field current, the OEL is switched to a timed setting, typically at 105% of the rated field current. The field current is not ramped down, but decreases almost instantly at switching. There are other manufacturers who provide OELs that ramp down the limiter set point from the instantaneous value to the timed limiter setting. The ramp rate can be either constant or a function of the amount of overexcitation.

Based on wintertime field measurements [1], we assumed Northwest active load to be 30% resistance and 70% constant current; we assumed reactive load to be reactance. Thermostatically-controlled loads were not represented, and would not have a large and rapid effect because of the distribution voltage regulation range assumed. We represented the loads on the low side of the bulk power delivery LTC transformers.

Installed undervoltage load shedding [1], [5] was not represented, but represents additional margin against transmission network voltage depression below about 92% voltage. Without operator actions, a small amount of load shedding might occur many minutes following the most severe first contingency outage.

C. *Outages Simulated*

Referring to Fig. 1, the 500-kV line outages simulated were Big Eddy–Ostrander, Ashe–Marion/Buckley–Marion double circuit, and Raver–Paul with outage of one Centralia unit (670 MW) because of breaker failure or bus configuration. The joint probability of the latter two multiple-related contingencies and extra heavy load conditions is very low and undervoltage load shedding is acceptable.

III. V–Q CURVE SIMULATIONS

For the three outages, Fig. 2 shows V–Q curves at the critical Ostrander 500-kV bus east of Portland. Also shown in the figure is the characteristic of the shunt capacitor bank at the bus. The bank provides 632 MVAr at nominal voltage. The stability margin is calculated as the difference of the bottom of the V–Q curve and the shunt capacitor characteristic line.

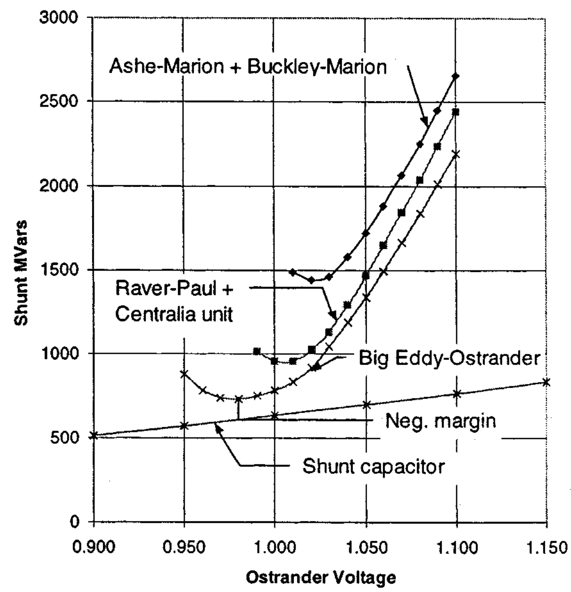

Fig. 2. VQ Curves at Ostrander 500-kV for three outage cases. The characteristic of the two existing 500-kV capacitor banks is also shown.

All cases have negative reactive power margin, which is considered *unstable* because of no operating point intersections with the capacitor bank curve. Because there are no operating points, results cannot be directly compared with results at the end of stable dynamic simulations.

IV. DYNAMIC SIMULATION

All cases were stable with 500-kV voltages in the 95% to 98% range. Voltages on the regulated side of bulk power delivery LTC transformers were in the 98% to 100% range.

The Big Eddy–Ostrander 500-kV line first contingency outage is interesting because voltage can decay for tens of minutes before steady state is reached. This was noted for a case with an assumed tap regulation range of 10%. Overexcitation limiting, which occurs at Centralia and John Day for this tap range, also takes many minutes. This slow voltage decay and overexcitation limiting is because of resetting of the tap changers after tapping returns regulated-side voltage within the control deadband.

The slow decay is significant because of the time available to minimize the partial voltage collapse by operator action. For example, BPA statistics show that line reclosing for nonmomentary 500-kV line outages is successful within 20 minutes 55% of the time and is successful within 30 minutes 62% of the time.

For voltage problems, Northwest operators have standing orders specifying emergency countermeasures such as gas turbine startup. A capability at large Columbia River hydro plants consisting of 10–27 units is fast startup of standby units for reactive power support. The units can run rough at light load for many minutes. BPA operators have a reactive power monitor indicating reactive power reserve of both running and standby units [8].

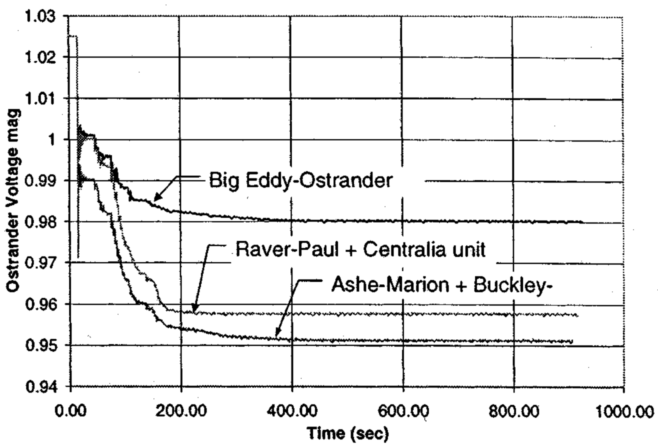

Fig. 3. Portland area: 500-kV voltage for the three outages.

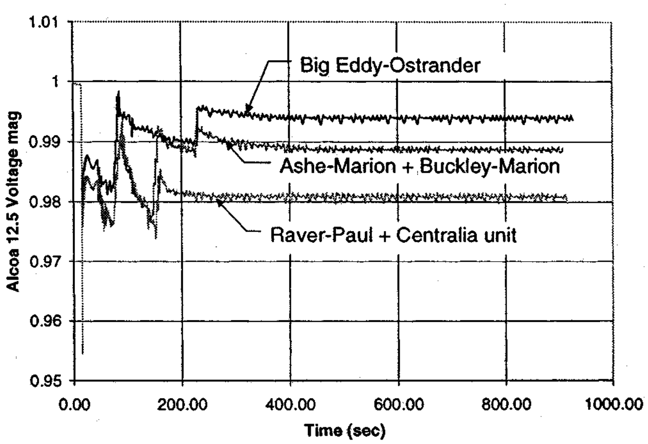

Fig. 4. Portland area: 12.5-kV voltage for the three outages.

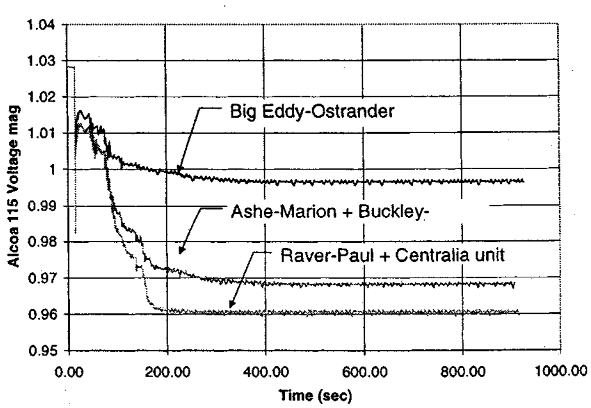

Fig. 5. Portland area: 115-kV voltage for the three outages.

Figs. 3–7 show results of time domain simulation for tap range of 5%. The results are further described in the following section.

V. Comparisons

All three outages are stable for benchmark dynamic simulation and unstable by V–Q analysis using conventional power

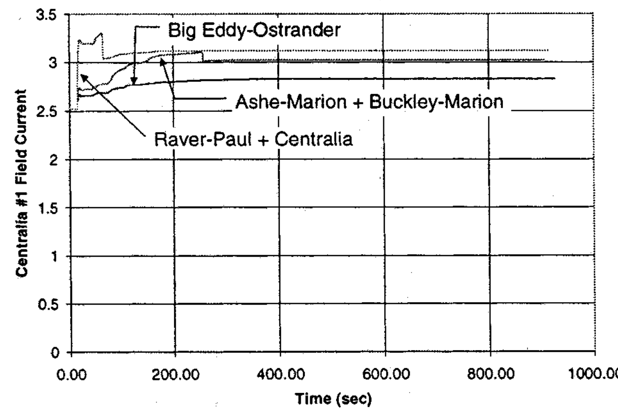

Fig. 6. Centralia-unit field current for the three outages.

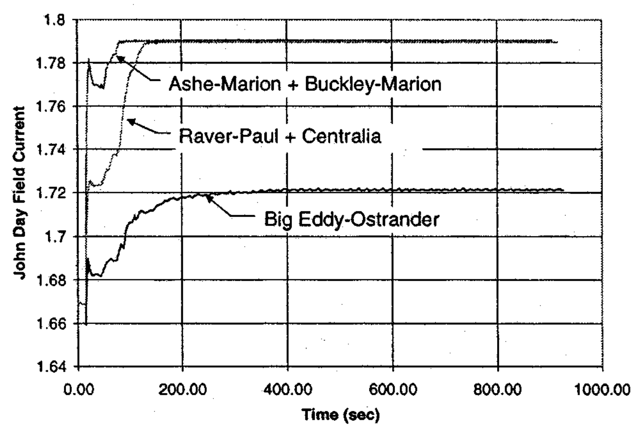

Fig. 7. John Day field current for the three outages.

flow models. Because there is no operating point for the unstable V–Q curve cases, results at the end of stable dynamic simulation cannot be directly compared with the power flow results.

For the first contingency Big Eddy–Ostrander outage, the V–Q curve method power flow simulations indicate need for reinforcements. In fact, a 550-kV, 460 MVAr, $3 million shunt capacitor bank at Keeler substation was determined to be necessary, and was energized in December 1998.

We can judge the acceptability of the stable dynamic simulations by the post-disturbance voltage levels, the remaining reactive power reserves at generating plants, and the time available for operator action. The installed undervoltage load shedding is a factor for reliability and risk assessment.

A. Big Eddy–Ostrander Outage

V–Q curve power flow analysis showed a negative 148 MVAr margin at the weakest 500-kV bus—Ostrander, as shown in Fig. 2.

The Big Eddy–Ostrander outage is stable using the benchmark time domain simulation with remaining reactive power reserves at generators as shown on Table I. All generators maintain reactive power reserve. Other smaller generators affecting the Portland area also were within the continuous reactive power limits used in power flow simulation.

TABLE I
POST OUTAGE MVAR RESERVES AT NEARBY GENERATORS

	Margins		
Plant	Raver -Paul Centralia 2	Big Eddy-Ostrander	Ashe-Marion + Buckley-Marion
WNP-2	160	185	165
BOARD_F 24.0	50	95	65
CENTR_G120.0	0	60	0
CENTR_G220.0	0	60	0
CHIEF_J213.8	33	33	23
CHIEF_J513.8	216	216	196
CHIEF_JO13.8	34	34	24
COULEE_213.8	99	134	109
COULEE1915.0	107	107	87
COULEE2015.0	107	117	97
COULEE2115.0	107	117	97
COULEE2215.0	170	175	155
COULEE2315.0	170	175	155
COULEE2415.0	170	175	155
DALLES_113.8	0	36	0
DALLES_313.8	125	210	90
DALLES2113.8	128	188	108
ↄALLES2213.8	57	97	47
OHN_DAY13.8	0	155	0

Post-disturbance Portland area 500-kV voltages are about 5% below pre-disturbance values. Most LTC-regulated bus voltages are restored within the voltage regulator deadband.

The discrepancy between power flow and the post-disturbance steady state of dynamic simulation requires discussion. Referring to Fig. 4, one reason is the effect of tap changer deadbands. If average post-disturbance regulated voltage is 0.5% below the center of LTC regulator deadbands, load relief (incomplete load restoration) of 60–100 MW would occur. The relatively small load relief and resulting higher voltage reduces transmission reactive power losses and increases line charging and the output of shunt capacitor banks.

The V–Q curve result is considered to be unstable. Considering the low joint probability of the outage and the extreme weather, the *stable* result from time simulation may be acceptable with only small reduction of load served. With somewhat less stress, V–Q curve results will still be unacceptable (BPA has used a 500 MVAr positive margin requirement). Dynamic simulation results, however, provides more information to judge acceptability.

B. Ashe–Marion/Buckley–Marion Double Circuit Outage

V–Q curve power flow analysis showed a negative 972 MVAr margin at the weakest 500-kV bus—Ostrander, as shown in Fig. 2.

The Ashe–Marion/Buckley–Marion double circuit outage was stable using time domain simulation, with remaining reactive power reserves at generators as shown on Table I. Typical regulated side voltages were around 2% low. Stability is because tap changing transformers reached boost limits.

Post disturbance Portland area 500-kV voltages are about 5–7% below pre-disturbance values. As shown on Fig. 6, the two identical Centralia units have overexcitation limiting. As shown on Fig. 7 and Table I, John Day reaches its continuous rating.

C. Raver–Paul Plus Centralia Unit Outage

V–Q curve power flow analysis showed a negative 371 MVAr margin at the weakest 500-kV bus. —Ostrander, as shown in Fig. 2.

The Raver–Paul plus Centralia unit outage was stable using time domain simulation, with remaining reactive power reserves at generators as shown on Table I. Typical regulated side voltages were 2–3% low.

Post disturbance Portland area 500-kV voltages are about 6–8% below pre-disturbance values. Stability is reached because tap changing transformers reached boost limits. As shown on Fig. 6, the remaining Centralia unit has overexcitation limiting. As shown on Fig. 7 and Table I, John Day reaches its continuous rating.

VI. Reliability Criteria

The acceptability of stable results depends on interpretation of adopted or mandated reliability criteria and other standards. Reliability standards are generally deterministic, but based on general knowledge of probabilities so that requirements for rare events are not excessive.

The recently-adopted WSCC criteria for voltage stability requires a 5% power margin for first contingency outages. Load shedding is not allowed. No interpretation is made of reduction of voltage sensitive load due to voltage depression. For the conditions simulated for this paper, the one-in-twenty year extreme load level is about 15% above the one-in-two year normal heavy loads.

We suggest a reasonable guide for first contingencies is to stay above the ANSI standard C84.1-1989 Range B service voltage [9]. This means that voltage at consumer service entrance should be above about 92% (e.g., 110 volts/120 volts). Range B voltages "shall be limited in extent, frequency, and duration." Modeling of equivalent feeder impedance or other evaluation of feeder drops is required. For the first contingency described above, this criterion is easily met, while V–Q analysis indicates instability.

VII. Conclusion

Although power flow analysis is suitable for screening, final decisions involving expensive reinforcements or operating limits should be confirmed by more accurate time domain simulation. (Time domain simulation is always needed when stability depends on the switching time of corrective countermeasures.)

For the wintertime load conditions studied, results from V–Q curve power flow analysis are not verified by more accurate time domain simulation.

Because of the widespread use of V–Q curve methods using conventions power flow program models, these findings and examples are significant.

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