Nuclear Generating Stations and Transmission Grid Reliability

Brendan Kirby, *Senior Member, IEEE*, John Kueck, *Senior Member, IEEE*, Harvey Leake, *Senior Member, IEEE*, and Michael Muhlheim

***Abstract* — Nuclear generating stations have historically been susceptible to transmission system voltage excursions. When nuclear generating stations trip because of voltage excursions, the resulting loss in real and reactive power support can exacerbate transmission events. New standards are being developed which should help improve nuclear plant and transmission system reliability. This paper provides a brief historical perspective. Nuclear plants do not provide automatic generation control in response to frequency decay and are also limited in providing voltage support. As 28 new nuclear plants are being considered for connection to an already highly stressed transmission grid, consideration must be given to nuclear plant design features that will enhance transmission system reliability.**

***Index Terms* — Nuclear Power Plant, Voltage, Fault, SCRAM, Trip, Transmission, Risk**.

I. Introduction

For transmission grid operators, the limited ability of nuclear power plants to supply reactive reserve for the support of grid voltage and to stay connected to the grid during voltage excursions is a problem. In this paper, we discuss a selection of nuclear plant trips that were caused by transmission system voltage excursions. Plant trips are also a concern from the nuclear safety perspective because trips due to voltage excursions are a major contributor to the risk of core melt. In probabilistic risk assessments to determine the risk of core melt, loss of offsite power is typically found to be the initiating event with the number one ranking, that is, loss of offsite power provides the highest frequency of accident sequences that result in core melt [1]. Plant trips are also a concern from the nuclear safety perspective because transients are a large contributor to the risk of core melt; increasing the number of plant trips directly increases the plant risk. In addition, nuclear plants typically do not help to regulate transmission system frequency with automatic governor control. As more and more new generation does not provide frequency regulation, the bulk power system's response to frequency has declined, which has a serious impact on bulk system reliability. Twenty-eight new nuclear plants are now being considered for license application according to the NRC. Some of these may be completed as early as 2014, while it can easily take ten years or more to design, permit, and build new transmission lines. Presently, operating margins are being eroded on the transmission system because of the connection of new generation, higher flows, and the delay in building new transmission. The connection of these new nuclear plants to the grid will present a significant problem to grid reliability unless design improvements are made to enable them to regulate voltage and frequency as conventional generators do.

Progress is being made in resolving some of these issues. Requirements for generator voltage ride through are being developed in some regions for wind plants, and these may also be applied to nuclear plants. The North American Electric Reliability Corporation (NERC) is developing a new standard that discusses the interface requirements between the grid and the nuclear plant. Interestingly, the Palo Verde nuclear plant showed its ability to ride through a significant voltage disturbance. A design review had been performed earlier to enhance the plant's ability to survive voltage transients. It is possible that new nuclear plants could be designed to be less vulnerable to transmission voltage excursions. This is certainly encouraging, but the authors are not aware of any similar efforts to encourage nuclear plants to regulate system frequency or provide automatic generation control. New nuclear plants should ideally perform as "good citizens" of the grid. They should regulate voltage, respond to frequency deviations, and supply dynamic reactive reserve. This paper provides a brief historical overview and a discussion of the issues.

II. Power System Voltage Transients and Generator Ride Through Requirements

A. Historic Voltage Ride Through Requirements

Faults on power systems are inevitable, and power systems generators must consequently be designed to ride through normally cleared bolted three-phase faults without disconnecting. Relays detect faults and circuit breakers clear them, but this takes time. Generators that are close to the fault location will experience low voltages during the fault clearing interval. Local voltages may take a second or longer to return to normal after the fault has been cleared. Low voltages at the generator can present problems in two ways. First, generator control systems and auxiliaries may stop operating correctly. Secondly, the generator itself will be unable to deliver electrical energy to the power system, though it will likely continue to receive mechanical energy through its shaft. The generator will consequently accelerate and may be at too great an elec-

This work was supported by Oak Ridge National Laboratory, Oak Ridge, Tennessee 37831-6283, managed by UT-Battelle, LLC, for the U.S. Department of Energy under contract DE-AC05-00OR22725.

B. Kirby (kirbybj@ornl.gov), J. Kueck (kueckjd@ornl.gov), and M. Muhlheim (mulheimmd@ornl.gov) are at Oak Ridge National Laboratory, Oak Ridge, TN. H. Leake is with Arizona Public Service Co., Phoenix, AZ.

trical phase angle relative to the power system when terminal voltage is restored to remain stable. In either case, a generator close to the fault might be forced to shut down and take minutes to days to return to service.

Generators farther away from the fault would not experience significant voltage dips, but may experience high voltages and trip to protect themselves. The power system could be designed to withstand generator failures every time there was a fault, but this would be costly and require deploying contingency reserves much more frequently. More importantly, it would likely require utilities to operate with much greater contingency reserves. Depending on how sensitive the generators are to low and high voltages, a single fault might cause multiple generators to fail simultaneously.

Alternatively, generators could be designed to ride through faults and withstand low and high voltage events. This has been the design practice in North America, though it was not formalized in NERC rules until recently. The 2004 *NERC Operating Manual* defined "operating security" to include the ability of the power system to withstand excessive or inadequate voltage, but did not articulate specific generator requirements [2]. Control area operators and transmission owners were required to take whatever actions were required to maintain reliability, with many suggestions concerning reactive reserves and required studies, but specific generator capability requirements were not included:

"Devices used to regulate transmission voltage and reactive flow, including automatic voltage regulators and power system stabilizers on generators and synchronous condensers, should be kept in service *as much of the time as possible*." [2] (Emphasis added.)

The closest NERC came to establishing standards for generator voltage requirements was in Policy 6, *Operations Planning for System Restoration:* "Operation at abnormal voltage and frequency. Generators and their auxiliaries should be able to operate reliably at abnormal voltages and frequencies" [2].

Standard generator design principles and good utility practice resulted in most generators being able to ride through faults and support power system reliability. Historically the vertical integration of generation and transmission also led to a coordinated design philosophy within each utility without the need for the voltage ride through requirement to be articulated in NERC standards.

B. Current and Proposed Voltage Standards

Restructuring of the electric power industry and the introduction of competition has provided many benefits, but it has also led to a need for more specific reliability requirements. Some feel this is a benefit too, because more specific requirements also lead to more rigorous design and operations. Clarity concerning generator low-voltage ride through capability came from a surprising direction: wind generators and the Federal Energy Regulatory Commission (FERC).

Current commercial wind generators are typically based on induction machines rather than synchronous machines. This lets them partially decouple the mechanical rotation of the turbine itself from the specific power system frequency. Some modern machines, however, are inherently more sensitive to low and zero voltage. As a result it became important for wind developers and manufacturers to know exactly what voltage ride through requirements they would be expected to meet, and they wanted the certainty of standards that were consistent from location to location and stable over time.

Wind developers proposed a voltage ride through standard as part of FERC's Order 661 "Interconnection for Wind Energy" [3]. FERC established a low-voltage ride through (LVRT) capability standard as part of Appendix G, "Interconnection Requirements for A Wind Generation Plant," which itself was made part of the standard "Large Generator Interconnection Agreement." FERC's Order 661 LVRT requirement is shown in Fig. 1.

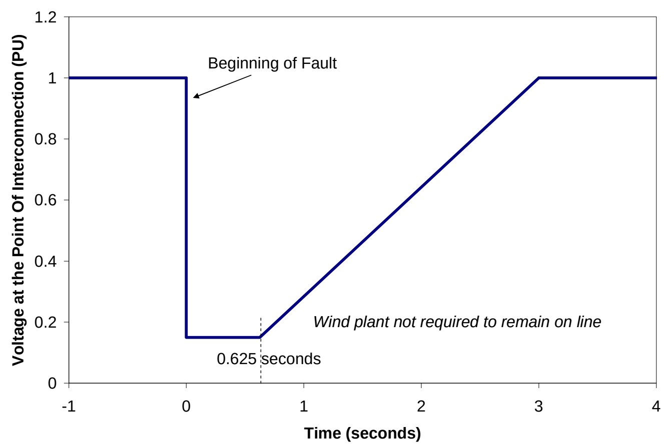

Fig. 1. FERC Order 661, "Minimum required wind plant response to emergency low voltage."

The low-voltage ride through requirement FERC adopted in Order 661 is odd in that it does not require the generator to withstand zero voltage and therefore does not protect against a close-in bolted three-phase fault. Both the American Wind Energy Association and NERC have asked FERC to reconsider Order 661 and establish a different low-voltage ride through standard. The two organizations negotiated a standard requiring wind plants to be able to withstand zero voltage for 9 cycles. FERC adopted this requirement in Order 661A on December 12, 2005. No voltage recovery period was specified, so the resulting curve is as shown in Fig. 2. (The curve itself was not included in Order 661A.)

This FERC standard currently applies only to wind plants. The Western Electricity Coordinating Council (WECC) Wind Generation Task Force (WGTF) has proposed to establish a technology-neutral standard for all generators that will address voltages during the fault itself and the recovery period, and also establish high voltages which generators would have to ride through. A detailed discussion of the WGTF analysis is available in a WECC white paper, "The Technical Basis for the New WECC Voltage Ride-Through Standard" [4]. Version 5 of the voltage ride through proposal is shown in Fig. 3.

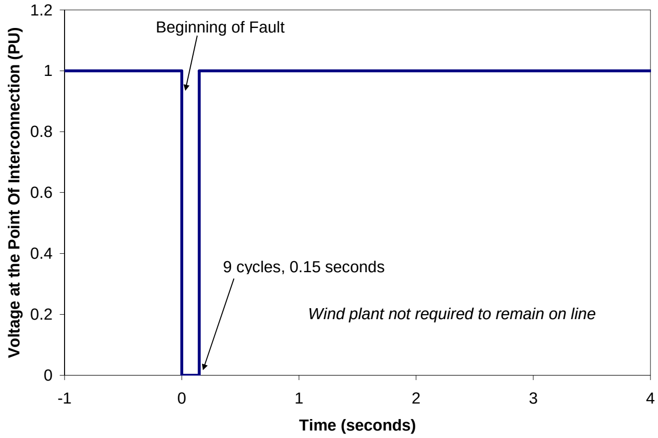

Fig. 2. FERC Order 661A requires wind generators to remain connected for voltages as low as zero lasting for up to 9 cycles.

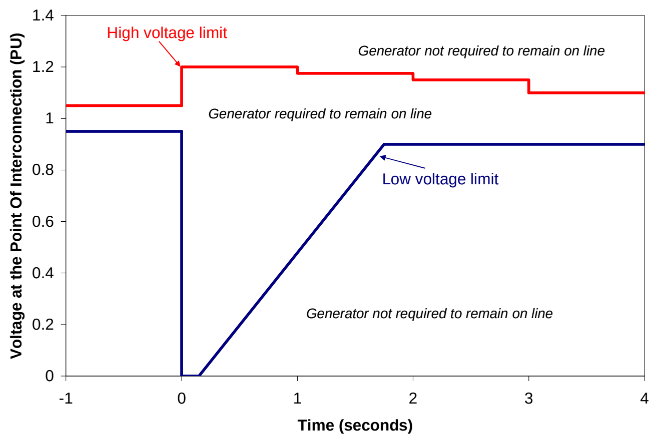

Fig. 3. Proposed WECC voltage ride through requirements for all generators.

The proposed WECC standard is a step forward with its more comprehensive coverage of post-fault voltage recovery period and over-voltage requirements, and its applicability to all (future) generators. This proposed standard may be more appropriately adopted as a NERC continental standard.

III. Nuclear Power Plant Risk and Grid Instability

When a large generator trips, there is an impact to the transmission grid — a loss of real and reactive power support. The transmission grid must react quickly to this loss because if multiple contingencies have already occurred, the grid may not be able to respond in a satisfactory manner. Nuclear plant risk and grid instability are interrelated — the tripping of a plant can cause grid instability, and grid instability can result in the tripping of a plant. As an example of a plant-to-grid disturbance, consider how a turbine trip/reactor trip at the Virgil C. Summer Nuclear Power Plant affected three other plants and the grid [5]. Summer tripped because of a technician's error. Three other generating stations tripped while attempting to compensate for the reactive power support lost on grid. This event then turned into a grid-to-plant disturbance. As a result of the loss of the four generating stations, the voltage to the Engineered Safety Feature buses at Summer decreased below the setpoint of the under-voltage relay. The emergency diesel generators started and supplied power to these buses. Although the event at Summer went both ways — plant to grid and grid to plant — this discussion is concerned with how disturbances on the grid can affect the safety of a nuclear power plant.

When evaluating how the grid affects nuclear power plants (NPPs), most studies focus on loss-of-offsite-power (LOOP) events, where all offsite power lines into the plant are temporarily deenergized. A LOOP event typically results in an automatic scram of the plant and the actuation of several safety systems. LOOP events represent a measurable fraction of a plant's risk based on plant-specific probabilistic risk assessments. Increasing the number of LOOP events directly increases the risk of damaging the plant. Conversely, reducing the number of LOOP events reduces the number of challenges to plant safety systems. In turn, reducing the number of challenges to safety systems reduces the risk to the plant.

More important to the risk profile of a plant are those disturbances on the grid that result in tripping the reactor or turbine. In fact, it is much more likely that a disturbance on the grid than a LOOP event will lead to a reactor trip (there were 69 trips versus 10 LOOP events between 1993 and 2003). Therefore, maintaining or improving the reliability of the grid would improve the safety of the plant.

To determine the magnitude of grid disturbances affecting NPPs, the authors selected the licensee event reports (LERs) that involved high-voltage distribution systems, actuations of engineered safety features, and plant transients between 1993 and 2003 using the Sequence Coding and Search System [6]. LERs of interest were those where a disturbance on the grid caused some action at an NPP.[1] Other grid studies and LOOP event studies were also reviewed for completeness and insights.

Table I shows the actions taken by the NPPs in response to grid disturbances, which included plant trips or scrams (56%). In those instances where the reactor remained at power, another bus and/or the emergency diesel generator reenergized the affected bus (25%). In some instances, an emergency diesel generator started but did not load (7%) or no action was taken by the plant (7%).

The actions taken by the NPPs resulted from grid conditions including voltage, current, and frequency fluctuations, or

[1] Not included are events such as operability conditions where exceeding previously analyzed values results in the "inoperability" of the offsite power sources. These analyses include statements such as "*if* this happens, then that *might* happen." For example, on August 11, 1999, the Callaway plant tripped for reasons associated with the rupture of a reheater drain tank line — not because of grid disturbances. On August 12, 1999, the licensee observed switchyard voltages fall below the minimum operability limit established in station procedures because of a large power flow coupled with a high local demand, and the loss of the Callaway generator. Switchyard voltage at the site dropped below the minimum requirements for 12 h (it was still available). Although offsite power was available during the reactor trip transient, the post-trip analysis showed that *if* additional onsite loads had been in operation at the time of the event, 4.16-kV distribution voltage *might* have decreased below the set point of the second-level under-voltage relays, separating the loads from offsite power. Also not included are plant-centered disturbances (which occur inside the control area of the plant) and LOOP events.

no power on the line (Table II).[2] No power on the line could occur when, for example, a direct feed line is cut or a tower is downed. Thus, contingency analyses must consider not only voltage, but also current and frequency. Interestingly, losses of power on an incoming line or voltage fluctuations are much less likely to cause the plant to scram than current imbalances or frequency oscillations. Typically, the grid is highly unstable by the time the current and frequency start to experience large fluctuations.

TABLE I
GRID DISTURBANCE EFFECT ON NPP (1993 – 2003)

Action taken by NPP	Number of occurrences	Percentage of occur-rences
Scram	69	56
No scram	51	42
Emergency diesel generator (EDG) energizes bus	19	16
Another source energizes bus	11	9
EDG(s) started but not loaded	8	7
No action taken	9	7
Power reduction	4	3
Unknown	3	2

TABLE II
GRID CONDITIONS AFFECTING NPP (1993 – 2003)

Grid condition	Number of occurrences	Number of scrams
No power on line	40	13
Under-voltage	34	14
Overcurrent	28	19
Over-voltage	15	8
Voltage fluctuation or drop	13	7
Under-frequency and over-frequency	8	8
Swing on load demand	3	2
Other	2	2

The major causes of the grid conditions that affected the NPPs are grid perturbations (including weather-related events) and equipment failures on the grid (Table III). In fact, disturbances resulting in a plant scram are about equally divided between grid disturbances (23 events) and grid equipment weaknesses and failures (25 events). Equipment failures include disconnect switches, circuit breakers, substation transformers, cables, capacitors, directional relays, insulators, lightning arrestors, relays, and voltage regulators.

Lightning (3), snow and ice (2), and high winds (5) were the causes of weather-related scrams. Lightning (4) and ice (3) were also the most likely causes of bus transfers because of weather (i.e., no scram).

[2] There is not a one-to-one correspondence between the number of scrams and grid conditions. There can be only one scram, but grid conditions can include up to four power lines affected, fluctuations of voltage, current, and frequency, etc.

TABLE III
INITIATING EVENTS FOR NPP ACTIONS

Initiating event	Number of occurrences	Number of scrams
Equipment failures (on the grid)	37	25
Grid perturbations (excluding weather-induced)	35	23
Weather[a]	32	16
Human errors	23	11
Fire (and resulting smoke)	5	0
Animals	3	0

[a]The major grid disturbance in December 1994 caused scrams at Diablo Canyon Units 1 and 2. The major grid disturbance in August 1996 caused scrams at Diablo Canyon Units 1 and 2 and at Palo Verde Units 1 and 3. Note that the Palo Verde event of June 14, 2004, discussed below does not fall into the time window of this table.

How important are the lines coming into a plant's switchyard? Over 50% of the scram-related events occurred because of some short-term grid disturbance (e.g., a "spike"), while all offsite power lines remained energized (Table IV). For example, on August 10, 1996, a transmission line sagged into a tree in Oregon and created a ground fault that progressed into a major fault on the western interconnection.

TABLE IV
NUMBER OF POWER LINES AFFECTED BY GRID DISTURBANCE

Number of lines without power	Number of occurrences	Number of scrams
0	59	35
1	37	14
2	11	6
3	5	3
LOOP events	10	9

The subsequent transient resulted in the tripping of Diablo Canyon Units 1 and 2 [7] and Palo Verde Units 1 and 3 [8]. The plants isolated from the grid and then tripped on protective signals even though all offsite lines to the plants remained energized throughout the event (the 500-kV lines to Diablo Canyon were declared out of service because of voltage and frequency fluctuations). In fact, almost half of *all* events generating a plant response (i.e., scram or bus transfer) occurred when all offsite lines remained energized. The loss of two to three lines, up to a LOOP event, does not necessarily generate a scram signal. For example, the LOOP event at Nine Mile Point, Unit 1, if it is defined as such, was so short (39 s total) that although the emergency diesel generators started and loaded, the plant reduced power and did not scram. Table IV shows that a transient is a much more likely occurrence than a LOOP event. Disconnect schemes and protective set points become more important to plant safety under such conditions.

IV. Nuclear Regulatory History and Developing Guidance

A. Nuclear Regulatory History

The transmission network depends on generators to provide power to customer loads, voltage support, and stability. Nuclear plants depend on the transmission network to provide a source of "preferred power" to emergency equipment, to support reliable plant operation, and to comply with regulatory requirements.

The primary requirements of the U. S. Nuclear Regulatory Commission (NRC) for power supplies to nuclear plant equipment are specified in Title 10 of the Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 17 (GDC 17). This regulation recognizes three major sources of AC power to nuclear plant equipment: the plant's main generator, its offsite power supplies, and its emergency diesel generators. GDC 17 requires a degree of independence between these three sources. It states, "Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit [the plant's main generator], the loss of power from the transmission network [the source of the offsite power supplies], or the loss of power from the onsite electric power supplies [the emergency diesel generators]." GDC 17 further requires that two independent circuits be provided to supply power to the plant from the transmission network: "Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits … designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure…."

Although the NRC's jurisdiction extends only to the boundaries of the licensed nuclear facilities, the commission has historically interpreted GDC 17 to include reliability criteria for the transmission network. The NRC stipulates in its Standard Review Plan that "The results of the grid stability analysis must show that loss of the largest single supply to the grid does not result in the complete loss of preferred power. The analysis should consider the loss, through a single event, of the largest capacity being supplied to the grid, removal of the largest load from the grid, or loss of the most critical transmission line" [9]. Since this expectation on the part of the NRC is enveloped by NERC's more stringent grid stability criteria, the jurisdictional question has not been an issue.

B. Possibility of a Nuclear Generating Station Supporting Its Own Area's Voltage

An NPP, like any other generating station, may support the voltage in the immediate area around the plant by supplying reactive power. Nuclear stations, however, will draw as much as 50 MW at a low power factor immediately after a generator trip when starting the needed shutdown auxiliaries. This sudden change from supplying reactive power to absorbing reactive power can cause the local grid voltage to drop. To quote the NRC, when an NPP generator trips, "Foremost among the grid changes is a reduction in the plant's switchyard voltage as a result of the loss of the reactive supply to the grid from the NPP's generator. If the voltage is low enough, it could actuate the plant's degraded voltage protection with subsequent separation of the plant safety buses from offsite power. A less likely event would be the trip of a nuclear plant causing grid instability and subsequent LOOP due to the loss of the real and/or reactive power support being supplied to the grid from the plant's generator" [10].

For this reason, some nuclear plants are prohibited from supporting local voltage. If there were a nuclear plant trip, the voltage could fall below the minimum level required to start the nuclear plant safety equipment. In these cases, the nuclear plant's voltage regulator is limited by procedure, and local reactive power sources are used instead to regulate voltage.

In the August 14, 2003, blackout, nine nuclear power plants tripped from the voltage and frequency fluctuations that occurred at the beginning of the blackout. Some of the nuclear power plants were in areas of "voltage susceptibility" or inadequate reactive power, and these plants were supporting voltage to the maximum of their reactive capability. For these plants, it was unlikely that post-trip voltage in the nuclear plant switchyard was going to be adequate to shut down the nuclear power plant, even if there had not been a widespread blackout. One of the goals of the new NERC standard (described in section IV.D) is that interface agreements will be developed between the nuclear generating station and the transmission operator to ensure that post-trip voltage is adequate.

C. Cascading Generator Trips

When multiple nuclear power plants are allowed to support the voltage in a given area, the post-trip voltage situation described above could be much worse. If the trip of one nuclear generating station could cause voltage to drop down into the trip range of a second station, then the second station would trip and a cascading trip sequence could occur. It is critically important for operators to know when they are on the threshold of such a scenario. This condition must be made readily apparent to operators and must be avoided. The literature has extensive discussions of cascading failures and methods for detecting them. "High-level probabilistic models of cascading failure and power system simulations suggest that there is a critical loading at which expected blackout size sharply increases and there is a power law in the distribution of blackout size" [11]. The new NERC nuclear plant interface standard discussed below will address interface requirements intended to provide warning to nuclear plant operators well before they are unknowingly operating on this threshold.

D. New NERC Nuclear Plant Interface Coordination Standard NUC-001-1

NERC, the FERC-designated electricity reliability organization, is preparing a standard for the interface between the grid and nuclear power plants. The NERC website [12] describes this new standard by stating that "Nuclear Power Plant licensing requirements specify that the grid be used as the primary source of normal and emergency power to plant equipment required for safe shutdown .... Thus, the bulk transmission system must be planned and operated in a manner that assures grid voltage, frequency, and stability requirements at the NPP will be met ....”

The purpose of the standard states, in part, that “Coordination is necessary to ensure that the entities responsible for the planning, assessment, operation, and analysis of the electric system are aware of the specific licensing requirements of each NPP and that they incorporate these NPP requirements into the planning, assessment, operation, and analysis of the electric system…. Typically, the need for this coordination is addressed in interconnection, interface, or other agreements” [12]. The authors anticipate that as these interface agreements are developed, a much better understanding of the dynamic relationship between the nuclear generating station and the grid will come to light.

V. Discussion of Palo Verde Event of June 14, 2004

Another event that put a nuclear plant in jeopardy occurred in 2004 at the Palo Verde Nuclear Generating Station in Arizona. It involved loss of the offsite power supplies to all three Palo Verde units, tripping of the three Palo Verde generators, and tripping of several other conventional generators in the area for a total loss of approximately 4,600 MW of generation. Approximately 65,000 customers were affected in the Phoenix and Tucson areas for up to two hours.

Since the event involved the complete isolation of the Palo Verde switchyard from the transmission network, it would have been impossible for the generators to ride through the disturbance. They did, however, remain on line for a remarkable length of time during severe voltage fluctuations and power swings—until the last transmission line tripped about 25 seconds into the event.

On the morning of June 14, 2004, a phase conductor on a 230 kV transmission line in the Phoenix area fell onto a transmission tower below, creating a line-to-ground fault. Electrical protective relaying on the system did not operate as designed to isolate the fault. About 12 seconds into the event the condition degenerated into a three-phase bolted fault due to failure of overhead transmission tower ground wires. At about the same time, three of the seven 525 kV transmission lines into the Palo Verde switchyard tripped because of sustained negative sequence current. These changes caused a significant drop in Palo Verde switchyard voltage and very high Mvar flows in the remaining 525 kV transmission lines and from the three Palo Verde generators. About 25 seconds into the event the last of the transmission lines connected to the Palo Verde switchyard tripped, causing a complete loss of offsite power to the site. Then all three Palo Verde units tripped. Fig. 4 is a voltage plot of the Palo Verde switchyard during the failure.

VI. Why did Palo Verde “Ride Through”?

The Palo Verde generators automatically regulate their output voltage in response to transmission system voltage changes. During the June 14 event, this regulation insulated, to some extent, the plant equipment downstream of the main

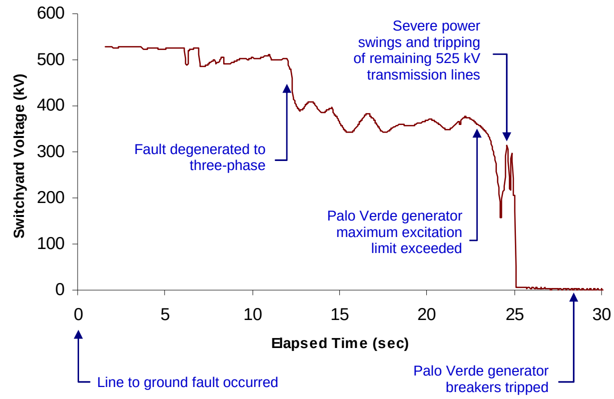

Fig. 4. Voltage plot of the Palo Verde switchyard during the June 2004 event.

generator from the voltage effects in the switchyard. This includes all of the equipment needed to support generation.

A. Palo Verde Possible Design Differences — Balancing Risks

Palo Verde staff have carefully reviewed a broad range of equipment protection systems to determine whether the consequences of their protective actions present a greater risk to the plant than the adverse conditions they are designed to protect against. The plant operates more robustly now as a result of changes they have made.

Not all of the plant equipment is fed from the main generator during power operation. The safety-related buses are fed from the 525 kV switchyard that experienced the severe voltage fluctuations without any voltage-regulating effect from the Palo Verde generator itself, so the voltages at the lower levels were affected proportionally to the switchyard changes. However, none of the safety-related equipment would initiate a generator trip because of low voltage or loss of power. Those systems are designed to sustain deenergization, then reenergization, from the emergency diesel generators without affecting power generation. The primary design function of the safety-related AC electrical system is to provide power needed to support reactor shutdown and to mitigate design basis events such as a loss-of-coolant accident. Therefore, during normal power operation, most of the safety-related equipment is deenergized. During the June 14, event, when switchyard voltage was abnormally low, the low voltage did affect the energized equipment and caused some of it to trip, including battery chargers for the safety-related batteries and charging pumps that control reactor coolant inventory. However, the plant is designed so that temporary disruption of the power to these components affects neither the main generator nor nuclear safety.

There have been cases where nuclear plants have tripped during a switchyard voltage disturbance because of under-voltage settings on the large reactor coolant pumps that circulate water through the reactor and steam generators. This is not a concern at Palo Verde because the reactor coolant pumps do not have under-voltage relays. The upstream 13.8 kV switchgear buses do have under-voltage relays, but they are set with a sufficient time delay to ride through most transients without dropping out. Palo Verde conducted a review of protective device settings and functions for the main generator to identify trip initiators that were unnecessarily sensitive and to optimize those functions to provide both reliability and security. The under-voltage relay time delay settings (one second or longer) for the critical plant distribution buses were determined to be long enough to ride through transients cleared by either normal or backup protection schemes. Also as a result of this review, generator transient torque protection was removed. It had been included as part of the design of the subsynchronous oscillation protection scheme to protect the turbine/generator from a possible capacitive energy surge during nearby transmission system faults. The review found that the probability of a damaging transient torque condition was very small, and the probability of a spurious generator trip was too large to justify maintaining this feature. The fact that the generators rode through the severe disturbance of June 14, for as long as they did without equipment damage is evidence that the protective device review effort was worthwhile.

B. Double Sequencing

Beginning in the late 1970s, nuclear plants installed degraded voltage relays at their safety-related switchgear buses, by the direction of the NRC, to transfer power from the offsite circuit to the diesel generator in the event of a sustained low-voltage condition. In the 1990s, the nuclear industry came to the realization that this design creates an issue with the NRC's GDC 17 requirement that tripping of the nuclear plant's main generator should not cause loss of the offsite power circuits. During a plant design basis event, such as a loss-of-coolant accident, the generator will trip and the voltage at the safety-related switchgear will change as a consequence of the event. This voltage effect results from the addition of emergency loads, possible loss of switchyard voltage support (for plants that obtain their offsite power from the same switchyard to which the main generator is connected), and automatic bus transfer operations. The degraded voltage relays are unable to predict what the voltage will be after these automatic operations take place. Since they are equipped with time delays to prevent spurious operation during system transients and the low-voltage condition will not occur immediately, the emergency equipment will always commence starting (automatic sequencing or block loading) on the offsite circuits. If the voltage subsequently drops to a level that causes actuation of the degraded voltage relays, the emergency equipment will then automatically trip and resequence onto the plant's diesel generators.

This temporary disruption of the emergency equipment is problematic for a number of reasons. The nuclear industry has addressed it by tighter administrative controls over switchyard voltages, implementation of predictive methodologies for post-trip voltage, and, at some plants, the installation of automatic voltage control equipment.

Because of the instrument loop uncertainties in the settings of the degraded voltage relays (such as tolerances and deadband), the presence of the protection scheme results in a tighter restriction on the allowable switchyard voltage range than would be necessary to satisfy the requirements of the plant equipment. The industry has suggested that the risks associated with double sequencing and the methods needed to prevent it might be significant enough to warrant removal of the degraded voltage relays [13]. The NRC, however, has not expressed a willingness to accept this as an option [14].

VII. Other grid-related issues — Frequency and Voltage Regulation

A. Automatic Generation Control (AGC) and the Declining Bulk Power System Response to Frequency

When the total system load and the total system generation are not equal, grid frequency changes occur. For example, when a generator or group of generators trip, the power system frequency suddenly declines, arriving at a new lower frequency in a few seconds. The automatic generation control (AGC) system is a control system that increases generator output to restore the frequency back to schedule. Nuclear power plants choose not to participate in AGC because of the philosophy that reactor power is to be controlled only by the nuclear plant operator, and not by outside variables. This position presents a growing problem because the grid frequency response is declining (Fig. 5). Combined governing response of the grid is measured by the parameter Beta, which is the constant of proportionality between the change in generation or load and the resulting frequency change [15]. The existing level of 31 MW/mHz is actually lower than conventional assumptions.

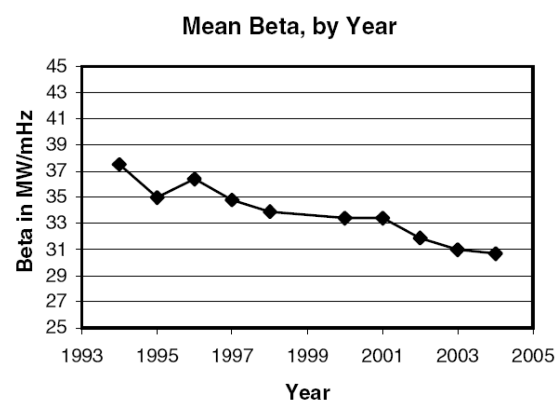

Fig. 5. Mean Beta computed for each year from 1994 through 2004. Data are not complete for 1999, so that year is omitted from the plot [15]. There has been a 12-year decline in frequency response while load and generation grew nearly 20% over the same period. Frequency response should have increased proportionally with generation and load. Conventional nuclear plants do not provide unit governor response [15].

This decline has a significant impact on transmission system reliability and it must be reversed. It is essential that future nuclear plants be planned to provide AGC and serve as good citizens of the grid. If more nuclear plants are connected without AGC, Beta will drop even more.

New nuclear plants can be designed to provide active governor control and respond to system frequency deviations.

Response will only be called upon when it is truly required for power system reliability. Moreover, conventional power plants are required to operate with active governors that incorporate a droop characteristic. If nuclear plants cannot redesign to provide governor response they should pay a penalty to make up for the frequency responsive reserve burden that they impose on other plants.

B. Voltage Regulation and the Shortage of Dynamic Reactive Reserve

FERC issued a report titled "Principles for Efficient and Reliable Reactive Power Supply and Consumption" [16]. The executive summary of this report states, "Reactive power supply is essential for reliably operating the electric transmission system. Inadequate reactive power has led to voltage collapses and has been a major cause of several recent major power outages worldwide." And while the August 2003 blackout in the United States and Canada was not due to a voltage collapse as that term has been traditionally used, the final report of the U.S. – Canada Power System Outage Task Force, April 2004 [17], said that "insufficient reactive power was an issue in the blackout. Dynamic capacitive reactive power supplies were exhausted in the period leading up to the blackout.… Not only is reactive power necessary to operate the transmission system reliably, but it can also substantially improve the efficiency with which real power is delivered to customers."

With an inherently limited capability to provide reactive power to support voltage, if a nuclear plant independently supports local voltage, the post-trip voltage may fall below limits. In some cases, it is difficult to accurately predict post-trip voltage in real time for a range of grid configurations. Some nuclear plants are limited in supporting voltage beyond a predetermined level, because adequate local reactive resources are not available. Reactive reserves are always available at a cost through such measures as static var compensators, synchronous condensers, or local generators brought on line just to ensure a stable local voltage, but it would be a huge advantage to the system planner and operator if nuclear plants were designed with the reactive power capability to be less voltage sensitive, as described in section VI. The authors hope that future nuclear plants are designed with this limitation in mind, so that they will be capable of riding through a wider range of switchyard voltage and do not impose difficult interface requirements such as the inability to provide reactive power and support voltage.

VIII. Conclusion

The NRC shows on their website that there are 28 new nuclear power plant applications expected as of April 2007. These new nuclear plants are being connected to a transmission grid which is being operated to its limits: "…operating margins against events 'beyond criteria' are being eroded by various means such as the use of parallel flow balancing devices, new generators placed to utilize the existing system, and pressure from transmission users to increase transfer limits. Flows on parallel paths are being equalized towards maximum capability… " [18]. System reliability is being taxed as it never has before. Extreme transmission system measures are being taken now to accommodate new generation that serves load growing in dense pockets and to connect renewable generation that is located in the "wrong" places. Adding 28 new large generators without AGC and with limited ability to control voltage would dramatically reduce grid reliability. It is essential that new plants be planned as generators which sustain grid reliability, or they should pay a reserve penalty and reactive power penalty to make up for the contingency and reactive reserve burdens that they are placing on other generators.

IX. References

[1] George E. Apostolakis, "Reactor Safety: The Emergence of Probabilistic Risk Assessment, Elements of Reactor Design, Operations and Safety," OpenCourseWare 22.39, Massachusetts Institute of Technology, http://ocw.mit.edu/OcwWeb/Nuclear-Engineering/22-39Fall-2005/LectureNotes/index.htm.

[2] North American Electric Reliability Corporation, *NERC Operating Manual*, June 15, 2004.

[3] Federal Energy Regulatory Commission, *Order No. 661, Interconnection for Wind Energy*, Docket No. RM05-4-000, June 2, 2005.

[4] Western Electricity Coordinating Council. "The Technical Basis for the New WECC Voltage Ride-Though (VRT) Standard – A White Paper Developed by the Wind Generation Task Force," June 13, 2007, available at http://www.wecc.biz/documents/library/TSS/Voltage Ride-Through White Paper_6-13-07.pdf.

[5] South Carolina Electric & Gas Company, Licensee Event Report (LER) 395-89-0 12, Virgil C. Summer Nuclear Station.

[6] R. B. Gallaher et al., *Sequence Coding and Search System for Licensee Event Reports*, NUREG/CR-3905, Vol. 1–4, April 1985.

[7] Pacific Gas & Electric Co., LER 50-275/96-012, Diablo Canyon, Units 1 and 2, April 17, 1997, "Reactor Trip on Units and 2 Due to Major Western Grid Disturbance."

[8] Arizona Public Service Co., LER 50-528/96-004, Palo Verde, Units 1 and 3, September 4, 1996.

[9] United States Nuclear Regulatory Commission, NUREG 0800: *Standard Review Plan*, Section 8.2: Offsite Power System.

[10] United States Nuclear Regulatory Commission Office of Nuclear Reactor Regulation, "NRC Regulatory Issue Summary 2004-05 — Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," April 15, 2004, available at http://www.nrc.gov/reading-rm/doc-collections/gen-comm/reg-issues/2004/ri200405.pdf.

[11] Ian Dobson, "Where is the edge for cascading failure? Challenges and Opportunities for Quantifying Blackout Risk," presented at IEEE Power Engineering Society General Meeting, Tampa, FL, June 2007.

[12] North American Electric Reliability Corporation Web site: http://www.nerc.com/~filez/standards/Nuclear-Offsite-Supply.html.

[13] J. D. Kueck, G. E. Attarian, H. C. Leake, and T. R. Sims, "Risk Factors Regarding the Application of Degraded Voltage Relaying at Nuclear. Generating Stations," in *IEEE Transaction on Energy Conversion*, vol. 16, issue 4, pp. 374-379, Dec 2001.

[14] J. D. Kueck, G. H. Nicely, J. Chiloyan, H. C. Leake, T. R. Sims, N. Trehan, G. Attarian, and F. A. Baxter, "A Discussion of Degraded Voltage Relaying for Nuclear Generating Stations," in *IEEE Nuclear Science Symposium, 1997*, Volume 2, pp. 921-926.

[15] James W. Ingleson and Dean M Ellis, *Tracking the Eastern Interconnection Frequency Governing Characteristic*, IEEE 0-7803-9156-X/05, 2005.

[16] Federal Energy Regulatory Commission, "Principles for Efficient and Reliable Reactive Power Supply and Consumption," Staff Report, Docket No. AD05-1-000, February 4, 2005.

[17] Natural Resources Canada, *Final report of the U.S.–Canada Power System Outage Task Force*, April 2004, available at http://www2.nrcan.gc.ca/es/erb/erb/english/View.asp?x=690&oid=1221.

[18] N. Dag Reppen, "Increasing Utilization of the Transmission Grid Requires New Reliability Criteria and Comprehensive Reliability Assessment," presented at the 8th International Conference on Probabilistic Methods Ap-

plied to Power Systems, Iowa State University, Ames, Iowa, September 12-16.2004.

X. BIOGRAPHIES

Brendan Kirby is a Senior Researcher in the Power Systems Research Program, Oak Ridge National Laboratory. His research interests include electric industry restructuring, unbundling of ancillary services, distributed resources, demand side response, energy storage, renewable resources, advanced analysis techniques, superconductive cables, transformers and devices, advanced overhead and underground transmission design, and power system security. In addition to the research topics listed above activities have included the Assignment to FERC Technical Staff to support reliability efforts including NERC/FERC reliability readiness audits. DOE Investigation Team for the 2003 Blackout, the IEEE SCC 21 Distributed Generation Interconnection Standard working group, DOE National Transmission Grid Study, staff to the DOE Task Force on Electric System Reliability, and NERC IOS Working Group. He has conducted research projects concerning restructuring for the NRC, DOE, EEI, numerous utilities, state regulators, and EPRI.

John D. Kueck has a BS in Physics and an MS in Electrical Engineering. He has been an electrical engineer with Sargent and Lundy Engineers, Combustion Engineering, and Carolina Power and Light. From 1992 to present, he has been a researcher at the Oak Ridge National Laboratory in issues regarding grid reliability, restructuring, and distributed energy.

Harvey Leake is a Senior Consulting Engineer at the Palo Verde Nuclear Generating Station. He received his electrical engineering training from Arizona State University and has thirty-five years experience in the design of power systems for generating stations and other types of facilities. He is chairman of Subcommittee 4 of the IEEE Nuclear Power Engineering Committee, chairman of the working group for IEEE 741, Electrical Protection for Nuclear Generating Stations, and a member of the working group for IEEE 765, Preferred Power Supply for Nuclear Generating Stations. He is also a member of the Nuclear Energy Institute's Grid Reliability Task Force and the EPRI Transformer and Switchyard Users' Group.

Michael (Mike) D. Muhlheim is a research and development staff member in the Advanced Reactor Systems and Safety group at the Oak Ridge National Laboratory. Dr. Muhlheim is involved in developing a prototype computer code called risk-based design optimization tool (RBOT) that allows designers to examine the reliability characteristics of design alternatives and observe how design changes affect the plants' ability to respond to different internally, externally, and shutdown-initiated events. Similarly, he developed a new prototype hybrid risk tool that overcomes the limitations of conventional PRA techniques for evaluating potential nuclear plant vulnerabilities that can arise from grid voltage inadequacies by using a detailed, real-time, dynamic PRA model of the entire electrical grid. Dr. Muhlheim received his Ph.D. in nuclear engineering from the University of Tennessee. He has authored or co-authored more than 50 journal articles and reports and is the 1996 recipient of the American Nuclear Society's Mark Mills award.