Preventing Future Blackouts by Means of Enhanced Electric Power Systems Control: From Complexity to Order

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Invited Paper

This paper concerns the critical role enhanced control will play in the operating of future electric power systems reliably and efficiently. The nonstandard control problems are due to a large variety of controllers, presently acting in a multirate mode at various levels of the system. Today's monitoring and control logic is largely effective during normal conditions. This paper concerns its possible enhancements which might enable the system to operate reliably over broader ranges of loading and equipment status. In particular, it is suggested that major benefits could come from providing computer tools to assist human operators with their decision making when the system is under stress. A multilayered approach is introduced to support: 1) on-line adjustment of available resources; 2) monitoring the interconnection based on qualitative indices (QIs) essential for deciding the severity of the operating mode; and 3) using the QIs to adjust structure of control as the system evolves from one mode to the next. An equivalenced model of the Northeast Power Coordinating Council (NPCC) interconnection is used to illustrate the potential of enhanced control in scenarios that resemble the blackout of August 2003. Also, the potential for efficient use of the resources during normal conditions is illustrated using this multilayered monitoring and control architecture.

Keywords**—***Advanced control, complex large-scale dynamical systems, electric power blackouts, electricity restructuring.*

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I. Introduction

This paper addresses difficult questions concerning the degree to which managing future electric power generation, delivery and consumption should and could rely on automatic control. In order to integrate power system monitoring and control tools effectively over a broad range of temporal and spatial horizons and for large deviations from nominal operation, we first re-visit the structure of the interconnection dynamics in the context of the nonstandard control problems of interest. The control of modern power systems can be analyzed as having open-loop response components, as well as components equipped with a variety of feedbacks. Feedback actions are either automated, or initiated by a human operator. Many of the feedback actions are in response to discrete events occurring at unplanned, asynchronous times and referred to as system contingencies. Typical system and control design has the objective of keeping the system within the stable and secure operating limits for any anticipated single contingency. The asynchronous discrete events also include relay actions, which generally disconnect pieces of equipment when acceptable state or control limits are exceeded. Therefore, any control design which takes into consideration control, state and/or output limits would automatically include relay actions. Some of the feedback actions are discrete both in time and in value, while the others are continuous. The resulting closed-loop hybrid (continuous and discrete) dynamics are very complex, and, are generally described by a set of coupled ordinary-differential equations (ODEs) (capturing continuous processes), discrete-time equations (DEs) (for discrete processes), and algebraic constraints for defining network system constraints.

To manage this huge complexity, an approach is suggested in this paper by which qualitative indices (QIs) could define type of operating mode the system is in, and could define corresponding multiple levels of abstraction and precision in the qualitative and quantitative organization of the closed-loop system response. An integrated multimodal approach recognizes different phenomena evolving on the system, and provides the minimum critical knowledge to those controllers whose logic has to be changed in order to effectively act as conditions change. The property of closed-loop monotone dynamic systems is suggested as the key property for justifying temporal and spatial separation of complex electric power system dynamics underlying their hierarchical control. As the conditions depart significantly from the nominal, this is reflected in the monitored QIs approaching abnormality and this is further used to indicate how controllers should change their logic so the closed-loop dynamics with the adjusted logic remain monotone, and, therefore, stabilizable. We discuss these concepts for both discrete and continuous controllers.

First, an equivalenced Northeast Power Coordinating Council (NPCC) 38-bus system is used to illustrate performance of the system with current controllers in place. Next the potential of enhanced, multilayered control is illustrated in the same system. Potential benefits for both enhanced reliability during contingencies and for efficient use of resources during normal conditions are described.

A. *Paper Outline*

The paper has two major parts: The first part provides an overall motivation for enhancing use of automatic control beyond current practices. In particular, in Section II a brief summary of the August 2003 blackout is provided. In addition to the reliability of service, economic and technological reasons to consider more automation while operating complex power systems of the future are reviewed.

The second part recognizes that in contrast with today's mostly uneventful operation facilitated to a large extent by means of hierarchical control during normal conditions, there is no comprehensive methodology for automated decision making when the system is outside the expected normal ranges of operations. Methods currently in place for operating the system during the abnormal conditions are reviewed for their implications on both technical and economic system performance. We set forward a vision for the enhanced control and analyze what might have happened in August 2003 had this control been possible. A possible framework based on the hierarchy of qualitative indices (QIs) and their use for on-line control selection and logic adjustments is described. The role of stabilizing distributed controllers in making a systematic switch between the operating modes (from normal hierarchical, to more complex as the conditions change) is stressed. Without this it is not possible to predict nor ensure a reliable service.

Analytical basis for the concepts in this paper is provided in the two appendices. These provide a review of power system operations, dynamics and today's operating practices with the emphasis on the critical assumptions underlying the structure of today's automatic control. In order to explain the multifold sources of a typical blackout-related complexity, this part of the paper summarizes functions and dynamics of interest and identifies the overall complexity and structure of the interconnection dynamics.

II. August 2003 Blackout in a Nutshell

This paper is motivated by the August 2003 blackout in the Eastern Interconnection of the United States and Canada. As documented in many of the postevent analyses [1]–[3], the most difficult aspects of preventing blackouts concern the type of on-line information needed, and its processing at the right time and at the right location. Given the overwhelming complexity of the electric power interconnection in the United States and in many other parts of the world, this is no small task. This recent blackout has confirmed an already recognized need for on-line adaptation as system conditions and network topology vary in order to minimize the effects of hard-to-predict-changes.

The August 2003 blackout affected large portions of the Eastern United States and Canada. This event brought home once more a recognition of the overall complexity in large-scale modern-day electric power interconnections. The complexity ranges from having a very large number of often nonuniform components, designed and deployed by different manufacturers, through spatial and temporal information, and, multimodal nonlinear system response to topological and input changes. The entire interconnection comprising many utilities is served by a single electrical power network. The high voltage (HV) transmission network connects large power plants to the large load centers within each utility. The utilities in each region are further interconnected via extra high voltage (EHV) transmission lines, often referred to as the ties; furthermore, there are several regions within the interconnection. The original intent of building tie-lines was to share the burden of providing electricity service when a particular utility within a region experiences a power shortage. The power shortages are usually caused by often hard-to-predict large equipment failures, such as power plants or transmission lines, and, less frequently, by the unusual demand patterns. Several regions themselves are also interconnected for both economic transfers and for sharing reserve in case of major equipment failures, as shown in Fig. 1.[1] The first triggering events of the August 2003 blackout were isolated failures of several transmission lines in one geographical area of the interconnection; the lines got disconnected by their fault protection after touching vegetation. The follow-up events were caused by the redistribution of flows through the remaining lines causing, in turn, other pieces of equipment to fail [1]–[3].

The exact analysis of the sequence of events is very complex and perhaps not plausible for a number of reasons. At least in principle, the scenario is seen as unacceptably

[1]At present, the boundary between power-equipment failure-related shortage and those caused by under-investments that fail to meet growing demand is difficult to draw. Some utilities and regions rely more heavily on imports during normal conditions than others. Current planning is mainly done at the utility and, sometimes, at the regional level. There has not been any coordinated planning among the regions at the interconnection level. Even the regional planning is becoming more challenging as the utilities compete for customers.

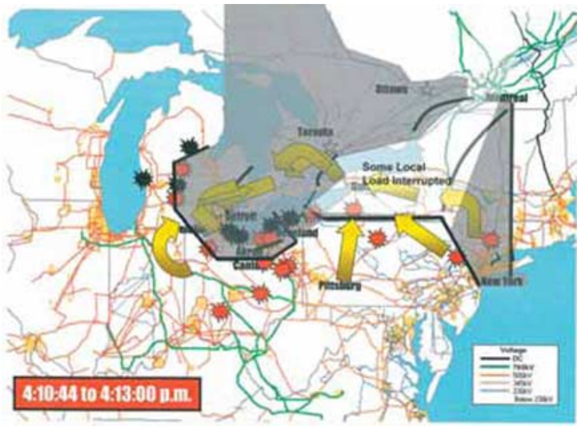

Fig. 1. The interconnection architecture of the Eastern United States and Canada [3].

high currents flowing through generators, transmission lines and other system components. For example, tie lines interconnecting two utilities may have been transferring unacceptably high current because power produced in the neighboring utility was being sent via these tie-lines into adjacent areas. Generally speaking, this led to an even more complex situation, where automatic control on power plants dedicated to maintaining system frequency would have adjusted their power output in response to initially slow and small frequency deviations. The increased power in one utility would have moved freely throughout the entire electrically interconnected network since the tie-line flows between utilities are not directly controlled.[2] It is generally this widespread effect of single events which causes protection of individual pieces of equipment to disconnect.

A likely sequence of events is that, since the loss of several transmission lines was not detected in a timely manner, massive power shortages or excesses developed in various portions of the system. These power imbalances resulted in unacceptable frequency deviations, causing maximum and minimum limits on frequency and voltage deviations to be exceeded, activating protection relays on individual generators and load centers and disconnecting many components throughout the system. Although under-frequency load shedding activated, under- and over-frequency protection of individual generators also activated and disconnected these. This led, ultimately, to a breakup of the large system into relatively small islands (such as Western and Eastern NY), at which stage generators in these areas experienced significant loss (or excess) of load ultimately causing loss of system synchronism and complete disintegration of the system. This could have ultimately led to a scenario of unsustainable net power imbalance and a complete system disintegration.[3]

[2]This is true except in cases of dc tie-lines and line flow regulators of one type or another. Depending on the type of such regulators, some are mechanically regulated and relatively slow (such as phase angle regulators (PARs), and some are much faster, such as series-compensated transmission lines. In today's interconnection the number of transmission lines with directly controllable flows is rather limited.

[3]This paragraph is a specific hypothesis by M. Ilić.

A. Automation Needs for Enhancing Reliability

As seen from the above summary of the August 2003 blackout, the basic challenge to current practices comes from having to operate the electric power systems over very broad ranges of disturbances, in particular demand variations and equipment status. These changes lead to multitemporal and multispatial variations of system states. The very field of electric power systems engineering which concerns modeling, analyses and control methods for operating electric power systems started after the early blackouts in the Northeastern part of the United States interconnection in 1960s and 1970s [4], [5]. Much progress has been made since. As a result, modern electric power systems are currently operated as large hierarchical control systems. The operating practices are based on these hierarchical control schemes, and enable efficient utilization of resources on a daily basis when demand disturbances are small around the forecast, and the equipment status is as anticipated. In Appendices A and B, we briefly review the underpinnings of these practices and the assumptions which ensure that this operation is largely effective. The simplicity comes from the ability to decompose one very complex problem into several simpler subproblems, with respect to both time and network size. However, we recognize in this paper that current operating practices are limited in their ability to ensure acceptable performance over a very broad range of varying conditions. Today's practices rely primarily on manual coordination between control areas with the NERC voluntary guidelines being the only backstop to ensure consistency and compliance. The events of August 2003 underscore the shortcomings of voluntary guidelines in a market oriented environment.

We suggest in this paper the consideration of an alternative more adaptive approach. Namely, as the loading conditions and equipment status vary, it becomes necessary to monitor these changes and to reschedule the available resources to best meet the new conditions. In addition, it is essential to adjust to hard-to-predict changes, small and large, fast and slow. Doing this on-line presents a major challenge to system monitoring and control. During normal conditions this approach would require monitoring and data processing into a valuable information to be used by the on-line decision tools. The minimal slow communications between different parts of the system generally suffices in normal operations and it is currently used for decentralized optimization of the available resources. The challenge is much more severe during major emergencies when effective coordination of system-wide reserve allocation is needed for preserving the system-wide integrity. It is illustrated in Section VII what can the system manage with and without such coordination. An *a priori* decomposition of the operating and control problem into subtasks commonly used for methods in support of normal operation may no longer hold. This requires then an on-line detection of the type of condition mode the system is in, and adaptive adjustments of control logic over all time horizons and electrical distances. In this paper, we consider possible systematic enhancements of current operating practices by means of on-line feed-forward decision making and feedback control to ensure acceptable service over a wide range of supply–demand patterns and equipment status.

In this paper, we attempt to provide a somewhat self-contained treatment of a typical blackout, its dynamics and dependence on control and to explain what might be essential to enhance in the future control of electric power systems. For example, a very large system may have enough stored kinetic energy in the moving rotors of all the generators connected to the network, so that when the fault takes place, the energy loss caused by losing the faulted piece of equipment gets compensated by the energy from other generators. The system may settle to a new equilibrium even without re-connecting the faulted equipment. To the contrary, if the system is pushed to the limits of its stability, the system stability may be completely lost. Deciding on when this occurs and how to prevent it from happening is the main objective of reliable operations for modern day electric power systems.

It is illustrated later in this paper that both the choice of control logic on generator controllers and adjusting their set points as the events unfold may make a qualitative difference between fault being transiently stable or unstable. If the logic of these controllers is tuned for different operating modes accordingly, then keeping the system intact during faults becomes a much less challenging task. As the power flow patterns vary and the equipment status changes, the control objectives and the logic of these controllers must be adjusted adequately for predictable performance.

B. *Automation Needs for Managing System Efficiently by Means of Novel Technologies*

While the challenge to reliably operating complex electric power systems of the future is clearly supported by the need to prevent wide-spread blackouts in the future, the needs for enhancing their overall automation for quantifiable performance is also related to the industry restructuring and also to the ability to implement fast power electronic switched hardware. There are at least three major additional reasons. First, existing transmission systems are being operated under loading conditions that challenge the capability of existing control systems. This is a result of changing environmental and economic demands on the power industry coupled with the difficulty and expense of providing new transmission capacity in response to the expansion and geographic redistribution of load. Second, the availability of flexible ac transmission system (FACTS) components such as static VAR compensators and thyristor-controlled series capacitors is creating opportunities for a redefinition of the transmission grid from an essentially passive system component to an active element that will play a major role in the operation of the power industry [6], [7]. These devices are capable of responding to system transients over a time scale of fractions of a second, making them suitable for controlling the short-term system response following system upsets such as equipment failures, short circuits and the like. In addition, the use of microprocessor-based control as an enhancement to established devices such as power system stabilizers (PSSs) has created the potential for higher performance control through the application of nonlinear control techniques such as variable structure control, feedback linearization, adaptive control and various paradigms currently lumped under the name of "intelligent" control. Third, recent breakthroughs in fast and inexpensive measurement and communications offer previously un-imaginable opportunities for monitoring and controlling events in timely manner over a vast area such as the US electric power interconnection. This includes on-line monitoring and communications with the end users for adaptive use of available supply.

III. Decision Making and Control for Reliable Operations: Reliability Revisited

Consider a multiarea electric power interconnection represented schematically in Figs. 2 and 4. Given the bounds on continuous time disturbances $\Delta d(t)$, the set of minute-by-minute discrete-time disturbances $\Delta d[k]$, the set of hourly disturbances $\Delta d[K]$ around the forecast real and reactive power demand $P_L[K]$ and $\hat{Q}_L[K]$ and the set of discrete hard-to-predict equipment failures of interest Δp, around given system parameters $\hat{p}$, design a framework for multirate multimodal decision making and gain scheduling of controllers distributed throughout the interconnection in order to ensure that quality of service specified to the end users in terms of frequency $\Delta\omega_{L,i}$ and voltage $\Delta V_{L,i}$ is within the prespecified limits. This also must be done within the safety limits for all equipment. Moreover, everything is to be performed at the reasonable costs.[4]

This problem, of course, does not always lend itself to a feasible solution for given system resources. Because of this, at the design stage one must establish requirements for sufficient control capacity needed to meet the above specifications. If adding a new controller is economically unacceptable, then control actions such as relaxing performance specifications on the customers' side must be considered. In this case, un-popular control actions such as partial load shedding are part of the required reliability framework. Historically, power systems have been designed in a sufficiently redundant manner so that the reliable service was not critically dependent on just-in-time decision/control actions. Decisions and control actions have primarily been for efficient scheduling of resources to compensate for hourly disturbances $\Delta d[K]$ during normal operations assuming no dynamic problems as long as local constant-gain controllers are correcting for presumably small deviations. During unplanned equipment failures reserves were used to ensure uninterrupted service.

A. *Need for Indicators of Abnormal Conditions*

In this paper, we point out that if the system is operated for whatever reasons over very broad ranges of conditions, it is practically impossible to differentiate between "normal" and "abnormal" conditions by simply looking at the equipment status. One may have equipment in place as planned, and still require more adaptive control logic for avoiding operating problems during unusual supply/demand patterns. Given this

[4]For detailed notation, see Appendices.

observation, we suggest that one needs manageable on-line metrics for estimating the severity of system conditions and, based on these metrics, a means of adjusting the control logic to make the most out of what is available. The implications of this on system model requirements are that one needs flexible models and monitoring tools for assessing the severity of system conditions and for adjusting the control logic accordingly as conditions vary within their hardware limits. Depending on the duration of the problem, one could allow temporary limit violations, delaying the disconnection of the protected equipment and, therefore, localizing the effect of the initial outage. This situation, however, would definitely raise the need for special protection schemes (remedial action schemes) (SPSs) to adjust the protection of the individual pieces of equipment to the system-wide conditions.[5] The SPS should also be used when control fails. The challenge is to define the type of information needed and its best use for overcoming the problem of uncoordinated disconnection of devices during emergency conditions. The implications of adopting such an approach are potentially far-reaching. As a basic example, transfer limits on key corridors would continuously be adjusted, drawing on all available resources for maximizing transfers, instead of assuming that transfer limits are determined only infrequently in an off-line mode. Another qualitative implication is that if this is done right, control adjustments would be systematic with respect to time, locations and type of controllers acting. For better or worse, modern-day electric power systems have many diverse types of controllers. It takes a tremendous intelligence to draw in an orderly manner on their overall potential as conditions change, without making matters worse.

B. *Role of Control for Implementing Efficient Economic Delivery in a Restructuring Electric Power Industry*

Important for the purposes of the concepts put forward in this paper is the fact that the control capacity needed to keep the system reliable, everything else being the same, greatly depends on the overall on-line monitoring, decision and control framework (logic, type, information supporting decisions, etc.) Planning and using reserve capacity (including control) for this purpose has been an off-line activity based on extensive numerical simulations and/or human experts' knowledge about the specifics of the situation. As the economic pressures increase, it is becoming more relevant to reduce capacity for the same performance by relying on just-in-time decision making. It is conjectured and illustrated in Section VII that generally more adaptive systematic use of available control reserves results in wider reliable ranges of operating conditions, all else being equal. In addition, since the services are provided at value, it is essential to enhance the value by means of control and communications. Various tradeoffs between the cost of reduced stand-by reserve by means of enhanced control, the cost of control/communications equipment and the values to industry participants and the system as a whole must be evaluated in the changing industry as the new hardware is being considered [48].

[5]Conceptually, a SPS is an embedded module (with the right sensing, communications and decision making) within the multimodal multilayered framework proposed in this paper.

C. *Theoretical Challenges to Moving Forward*

The appendices in this paper provide a review of current models and control practices. There we describe that the most general system dynamics of an interconnected electric power system can be represented as very high-order coupled differential algebraic equations (DAEs). Conceptually speaking, the state-of-the-art in decision making for large dynamic systems defined as DAE models, and driven by a mix of continuous, discrete-time synchronous and entirely asynchronous input and topological changes (also continuous and discrete in quantity), is not nearly ready to provide systematic solutions to the real-life problem posed here. In particular, there are hardly any methods for designing the control of predictable performance for DAE systems. Given this fact, the prospects of designing an entirely novel decision making/control framework for prespecified performance in complex electric power systems are rather slim. In this paper, we propose that it is possible, instead, to enhance the existing framework carefully by relying heavily on the underlying structure of the system dynamics of interest.

Part of the challenge is extracting the relevant structure. In Appendix A, we walk the delicate line of moving from a practically unmanageable very complex DAE system model to the ODE models for which the stabilization and regulation tools are more readily available. A multilayered approach is envisioned which enables one to move to useful contextual, temporal and/or spatial simplifications. In the process of doing this, we show that a recently formalized modeling for normal operations of the hierarchically arranged interconnection on which much of today's automated operations rests is a degenerate case of the more complex framework, see [30]. Several key QIs are defined whose status (normal, abnormal) must be monitored in order to enable a more adaptive multimodal decision making framework for reliable service.

IV. Hierarchical Control Systems of a MultiArea Interconnection

The basic objective of today's hierarchical control is to ensure that customers are served electricity of high quality at reasonable prices. This very broad objective is effectively accomplished within a horizontally structured interconnection by performing technical subobjectives at various hierarchical levels and over various time horizons. In a fully regulated industry these subtasks were fully defined within the utility (control area) boundaries. Traditional control areas (utilities) have built their transmission and production equipment to meet these objectives for the forecast load in their own area. Various complexities related to the interactions with neighboring utilities were resolved to a large extent through a design which has led to strong utility networks and weak interconnections between utilities. The implications of such design on the overall use of resources within the interconnection are briefly described next in the context of hierarchical control underlying the operation of such architecture.

A. Temporal and Spatial Decomposition of Control Tasks for Normal Operations

Based on the assumptions described in Appendix B, current hierarchical control is temporally decomposed so that the forecast load is supplied somewhat independently from the minute-to-minute automated regulation of power imbalances, and the regulation is, in turn, performed separately from the stabilization by the primary controllers of the individual pieces of equipment. These are, of course, interdependent, because power scheduling is performed by adjusting the set points of the controllers on power plants, and regulation is also done by adjusting the set points of power plants specifically dedicated to functions such as automatic generation control (AGC) or automatic voltage control (AVC) [13]. Stabilization is in response to fast load fluctuations so that the set points of the controllers remain at the values set by scheduling and regulation.[6] This decomposition is based on the multitemporal separation of a time-varying system load as well as on the intended decomposition of control tasks in balancing power.

Current control practices have evolved over time, and have never been designed to meet a prespecified reliable performance according to the objectives stated in Section III. Similarly, the models for the particular subfunctions (stabilization, regulation) have not been developed with the objective of being used in a control design aimed at meeting a prespecified performance. The process of gradual automation of electric power system operation has instead been primarily driven by often ingenious engineering inventions related to controlling the system at a particular spatial and temporal level (primary control of generator-turbine-governor (G-T-G) sets; scheduling and AGC of each control area (and its AVC counterpart in Europe); and, more recently, fast power-electronic switching of transmission network components for fast stabilization).

The net result of this uncoordinated process viewed from the interconnection level is a mix of many nonuniform (with respect to location, rate of response and type) controllers at individual pieces of equipment, as well as at each utility (control area) level. There is currently no on-line coordination of individual control areas within an electric interconnection. Consequently, it is practically impossible to predict the performance of closed-loop interconnection dynamics for any significant variations around the assumed (preagreed upon) conditions. The complexity in hand is, by many measures, unmanageable without imposing many explicit or implicit assumptions.

B. Cooperation as a Means of Managing the Interconnection and Its Complexity

The overall effectiveness of today's hierarchical control is based on the notion that each layer meets, in an entirely decentralized way, its own subobjective and that, as long as all members in each layer perform their own subtasks, the interconnection as a whole operates reliably. In particular, the primary controllers in power plants are tuned to stabilize their own local dynamics, assuming that all other power plants will do the same and maintain the system conditions as planned. Similarly, each utility performs its own supply–demand balancing via its own AGC, assuming that all other control areas are doing the same. Furthermore, all utilities attempt to schedule their own generation to supply forecast load, and send agreed upon power to the neighboring control areas. This overall operating practice is fundamentally reflected in: 1) the models used for scheduling, regulating the interconnection as a whole; 2) the spatial decomposition of tasks; and 3) the temporal decomposition.

Modeling and control design is invalid and ineffective unless each member within each hierarchical layer acts accordingly. In other words, it is practically impossible to have provable performance by the hierarchical control, decomposed both spatially and temporally, unless all agents meet their objectives. For example, it is well known that it is very hard, or impossible, for a single control area to schedule generation in a decentralized way unless all interconnected control areas also meet their preagreed upon schedules simultaneously. In the regulated industry, the principles of each control area meeting its own share have mainly been implied as part of normal operations [33]. We next describe the temporal decomposition of control objectives.

C. Real Power Scheduling, Regulation and Stabilization

In a horizontally structured interconnection, each control area schedules its own power supply to provide for its own (native) customers. This is done for prescheduled real power net power exchanges with the neighboring utilities. Current operating practice is for each control area (utility) I to schedule in a feed-forward manner real power generation $(P_G^I[K])$ to supply its own forecast demand $(P_L^I[K])$, for given net real power flow exchange $(\Sigma_{j\in K_R^I} F_{ij}[K])$ with the neighboring utilities; here, K_R^I represents the set of all buses in the neighboring control areas connected to the control area I and $F_{ij}[K]$ are the real power flows between buses in this control area and the buses at the boundaries of the neighboring control areas, see Fig. 2.[7]

Finally, as each control area attempts to schedule its net tie-line flow with neighbors, it is assumed that the interconnection as a whole will have a steady-state equilibrium, i.e that a power flow solution of the entire interconnection exists. Another way of interpreting this assumption is that the control areas are weakly connected, implying that each control area can schedule net tie-line exchange and maintain it in response to both internal and external perturbations [41]. We illustrate in Section VII potential problems that arise when the interconnection is used beyond the conditions which ensure the validity of this assumption.

[6]It is not always understood that the scheduling, regulation and stabilization involve the same physical device, i.e. the primary controller of a typical power plant. For real power/frequency regulation this physical controller is governor; for reactive power/voltage control this device is an automatic voltage regulator (AVR) and/or PSS; see Appendix A.

[7]Observe that only the net tie-line flow, i.e. the sum of all flows, is preagreed upon and not the flows in individual tie-lines. Moreover, typical practice has been to have only real power exchanges specified and not reactive power. We illustrate the consequences of these practices in the section illustrating the NPCC system.

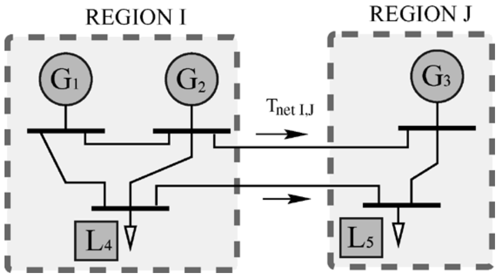

Fig. 2. An interconnected 5-bus power system.

An important observation concerning this decentralized approach to scheduling, regulation and stabilization is that for the interconnection as a whole to perform adequately it is essential that each control area meet its objectives. System design and capacity is planned and scheduled so that this load is supplied even during any single equipment failure. This means that the system is expected to have a power-flow solution for any single equipment loss, including the existence of a transiently stable postfault equilibria. It is difficult to imagine that exhaustive simulations can be performed for all possible scenarios even in the case of a small system. Such simulations are currently carried out by the industry to determine sufficient reserve for each control area and for regions. Each utility has in its control center a variety of computer-based and human-assisted approximate methods for assessing the severity of contingencies as they occur.

The minute-by-minute load deviations $P_L[k]$ from the forecast demand ($P_L[K]$ are regulated by the very few power plants adjusting the set points $\omega_G^{\rm set}[k]$ of their governors in response to these deviations. Secondary level control of each utility (AGC and/or AVC) adjusts the set points $\omega_G[k]^{\rm ref}$ and $V_G[k]^{\rm ref}$ of selected power plants participating in AGC and AVC, respectively. The objective of these secondary level controllers is to adjust relatively slow quasistatic imbalances in each control area in order to maintain the net tie-line flows $F^{\rm net}[k]$ to its scheduled value $F^{\rm sched}[K]$. The AGC is not intended for frequency stabilization during contingencies.

Another important means of regulating forecast real power imbalances are phase-angle regulators (PARs). These are line transformers whose taps are adjusted to maintain real power flows within the preset thresholds.

Frequency fluctuations caused by random fluctuations in real power load $P_L(t)$ are compensated for in an automated way by the governors controlling the amount of mechanical power applied by their prime movers. An important observation is that governor control is inherently a proportional type controller that does not compensate for the steady-state error in frequency deviations from the nominal frequency and/or tie-line schedules requiring a system-wide time-error correction by a dedicated power plant in order to compensate for the effects of the inadvertent energy exchange (IEE) between utilities. Finally, the fastest random deviations of generator voltages and frequencies are stabilized by the AVRs and PSSs of power plants. The tuning of these controllers is generally intended only for stabilizations of small disturbances. All controllers are constant-gain controllers, and are

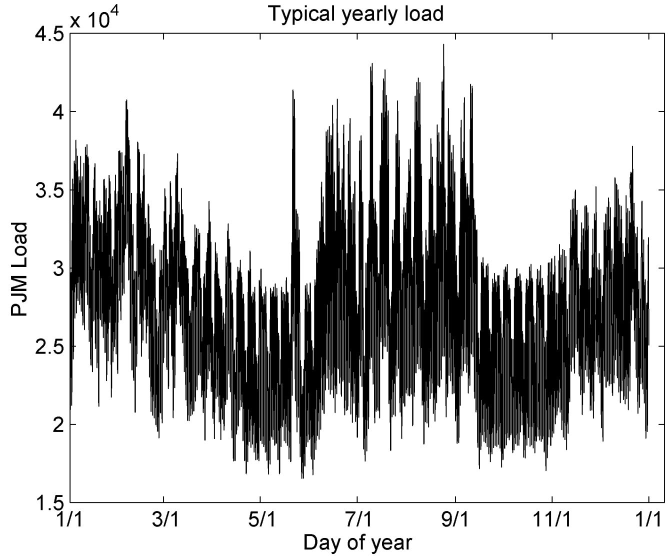

Fig. 3. Typical system load dynamics.

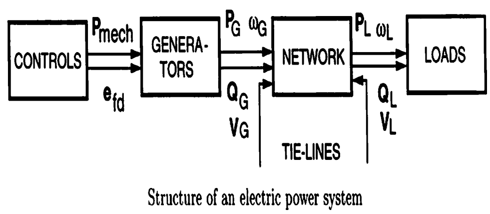

Fig. 4. Structure of an electric power system.

intended to stabilize disturbances around a statically and dynamically stable equilibrium. These controllers are generally not capable of taking the system from a prefault equilibrium to a stable postfault equilibrium outside the stability region of the prefault equilibrium. It is shown in Section VII how more advanced control in large-scale systems can be applied to achieve this.

D. Reactive Power Scheduling, Regulation and Stabilization

Scheduling and regulation of reactive power during normal conditions is done in a somewhat decoupled way from real power scheduling. Moreover, ensuring sufficient reactive power and voltage scheduling capacity has not been as standardized as real power capacity scheduling. Reactive power support can be provided either by the power plants, or by installing capacitive support to compensate for large reactive power transmission losses, or by installing shunt capacitors electrically close to the load centers. Current industry practices vary from keeping a large portion of reactive power capacity in generators for voltage scheduling as needed, to a more active scheduling and regulation by adjusting the set points of AVRs for supplying forecast reactive power load $Q_L[K]$, and for regulating slow reactive load deviations $Q_L[k]$ by the Automatic Voltage Control (AVC); the latter practice is used in France, Italy and Spain, in particular.

1) Mechanically Switched Capacitors and Transformers: Over time, different technologies have evolved for regulating medium- and long-range voltage deviations by adjusting reactive power support in the transmission system. In particular, mechanically switched on-load tap-changing transformers (OLTCs) [35] and shunt capacitors are routinely used for load voltage regulation. This is done by regulating the number of active taps in mechanically switched capacitor banks so that the steady-state load voltage is kept within the prespecified limits; most often this is done by adjusting OLTCs to control the number of active taps of the line transformer in order to regulate directly the receiving end load voltage; less frequently, the switching actions regulate remote voltages elsewhere within the system.

The process of regulating load voltage subject to power-flow constraints can be described as a control-driven process subject to the common algebraic constraint imposed by the need to meet the basic power flow balance at each quasistatic step. The convergence of this process driven by the mechanical switching of capacitor banks and OLTCs is critical for the stable regulation of load voltages within each utility, region and/or interconnection [36].

Several blackouts have been related to the "malfunctioning" of these devices, ultimately resulting in system-wide voltage collapse. The fundamental difficulty in such situations has been the inability of these switching devices to adjust their logic when there is not enough reactive power reserve. It has been shown that relaxing the currently implemented control, which essentially absorbs a constant amount of reactive power by forcing the voltage to remain within a small band, to a more adaptive scheme of reducing reactive power requirements temporarily under unusual circumstances could return the system to a more manageable condition and help the system as a whole to avoid voltage collapse [36]. In particular, recognizing a change in the qualitative characteristics of the system Jacobian derived from the model in Appendix A that defines changes in voltages as driven by the mechanically switched tap changers, and adjusting the control logic to reflect and compensate for the change, could help regulate voltages back to within the acceptable limits and avoid a system-wide voltage collapse [36]. This can be implemented as a sliding-mode type controller, but has not been implemented in practice; its potential may be significant. For purposes of assessing the overall potential of enhanced control, it is critical to consider the malfunctioning of a variety of reactive mechanically switched devices currently available in large numbers in typical transmission and distribution systems. Assessing how much of the reactive power burden now borne by generation could be reduced by more effective use of these resources in more adaptively regulating reactive power in transmission and distribution should be one of the main R & D objectives following the August 2003 blackout, in particular.

E. The Key Role of Stabilizing Control in Operating an Electric Power Interconnection

The increase in operating demands and the proliferation of advanced hardware have created a need for more powerful tools for planning and design. In many cases, the function of a particular piece of equipment may be defined in terms of a narrow set of objectives, such as the stabilization of a particular bus voltage or modulation of the power flows across a particular transmission interface, without addressing the system-wide effects of the device. This situation follows from the lack of a comprehensive design methodology for power system stabilization. The effect of this is that the selection and application of the equipment is done without any systematic method of ensuring that the control objectives are met adequately, efficiently, and without unforeseen consequences. Indeed, once the selection of a particular piece of equipment is made, the use of exhaustive time-domain simulations is currently the only method available for attempting to ensure that all of its capabilities are exploited, in the sense of fully realizing system-wide or even local benefits. The development of a coherent set of tools for evaluating the performance of various control devices in terms of immediate control objectives and system-wide effects must, therefore, be viewed as critical to the effective utilization of power electronically switched transmission and distribution network controllers (generically referred to as FACTS); the FACTS technology is very different from traditional mechanical switching because it is capable of enhancing fast power plant controllers and can be used as a means of implementing advanced control as it becomes available. It should be clear that if either primary controllers, such as governors, AVRs and PSSs, fail to stabilize fast dynamics, and/or the AGC fails to regulate the tie-line flows to their scheduled values, there exists the possibility of intercontrol area oscillations at various rates and of different degrees of severity that can threaten system stability [20], [21].

V. Current Practices for Controlling During Equipment Outages

As long as no major unplanned loss of equipment occurs, frequency and voltage deviations are kept within acceptable limits by the described stationary real-power prescheduling, the secondary-level AGC, regulation using mechanically switched controllers, and stabilization by constant-gain primary controllers. This rather simple control works well for relatively small load deviations around the nominal pattern for which the system is designed.

Current operating practice to ensure reliability identifies the "worst case" scenario for transient stability, and makes sure that sufficient reserve capacity is kept between the nominal operating point and the worst case condition, so that during such a fault a stable postfault equilibrium may be found. Both transient and dynamic stability studies are done off-line for such worst-case scenarios. A typical approach has been to simulate P-V steady-state transfer curves; assuming a constant ratio of real and reactive power demand consumption (power factor), off-line power-flow studies are carried out to obtain a dependence of receiving end voltage V in the real power transfer P. On the other hand, these simulations establish the maximum real power flow allowed. It is straightforward to conclude from the simple numerical examples that the maximum feasible real power transfer could be greatly affected by the AVR settings, which determine the voltages at generator nodes as long as there is sufficient excitation control available. Currently used industry software for calculating this line power transfer limit does not account for the potential of increasing the transfer by optimizing system voltages. Moreover, many other discrete-type control actions (OLTCs, switching capacitors on the load side) are not accounted for as this limit is computed. As a result, the computed limit is generally conservative.

In the on-line setting a contingency screening test is performed prior to dispatching real power generation to ensure that the system will be feasible for real power supply and delivery during any contingency. Linearized, distribution factor-based simulations are done for all contingencies.[8] More detailed power flow simulations are done for the list of contingencies determined to be critical. This amounts to restricting real power generation dispatch so that the line-flow limit does not exceed the maximum feasible transfer. For example, economic generation transfer is limited by this calculation, in case a limiting contingency happens to occur. This practice is preventive, and not corrective in its basic nature. The basic inability to schedule the least-expensive generation because of necessary stand-by reserves in case an outage occurs, generally results in economically suboptimal cumulative use of resources during normal operation.

Moreover, despite the fact that the reserve is kept, there is no guarantee that the system will be feasible during an actual equipment failure. More generally, the $(N-1)$ reliability reserve is assured for the assumed nominal load prior to the equipment outage. The planning studies may not be sufficient to ensure that the system will perform its basic function during the single equipment outage because at the time of the outage the loading and other conditions in the system may be considerably different than the conditions assumed at the planning stage. The closer the nominal (prefault) operating point is to the infeasible operating point, the smaller the next change is that causes the system to lose its feasibility, steady-state and/or transient. This very fact may have been crucial during the August 2003 blackout. As the loading conditions increased for economic transfers, the closer the nominal point (prior to equipment failures) may have come to the system feasibility and/or stability boundary. The effects of hard-to-predict equipment failures around such an operating point are, at least in principle, not computable by DF-based computations.

Possibly the most critical aspect of today's operations is the fact that as the system conditions approach small-signal- or transient instability the constant-gain slow control may no longer be effective. This is particularly true over broad ranges of disturbances of one type or another. Because of this, introducing a more adaptive logic that ensures system-wide stabilization is essential. Given the assumptions underlying today's hierarchical control, unless the system is stable, regulation and scheduling according to temporal and spatial decomposition become ineffective.

In what follows, we propose a possible multimodal approach to monitoring and controlling a complex electric power interconnection. This approach takes into consideration today's operating practices and, much like the early DyLiacco diagram suggested classification of conditions into normal, alert, emergency and restorative [4], [5], it proposes to use a family of QIs for detecting and quantifying the degree and type of abnormality and, based on this, adjust the underlying control. Again, the key to the overall enhancement is that the system be made closed-loop stable. Once this is ensured, the multilayered hierarchy already in place needs only to be made slightly more adaptive for the ensured reliability of the interconnection as a whole.

[8]A distribution factor matrix is a matrix defining the sensitivities of real power line flows to the nodal power injections at the various nodes [37].

VI. Toward a MultiModal, MultiLayered Monitoring and Control of Future Electric Power Systems

As electric power grids are operated away from the conditions for which they were initially designed, they may lose the properties of weakly interconnected stable networks. Consequently, the hierarchically managed system may fail to meet its objectives. The variations in system conditions are generally caused by significant variations in operating conditions and/or by major equipment failures. There is no distinct line between the effects of these two. As a matter of fact, it is well documented that often qualitative changes occur as the controllers reach their limits and the degree of controllability becomes compromised [23]. It is plausible that similar problems may take place if a critical measurement becomes unavailable, and the system is less observable.

Regardless of the actual root causes of such changes in the qualitative response of an electric power system, the hierarchical decomposition-based operation may result in very unpredictable events when the underlying assumptions are violated. It is a conjecture of the first author that this was the case during the later stages of the August 2003 blackout. The current approach is to rely on complicated off-line simulations of similar scenarios and to use these to assist human operators with the decision making under such conditions. These off-line studies are very time-consuming and are done for prescreened most critical equipment failures. This preventive approach requires expensive stand-by reserves that, no matter how large, may not ensure guaranteed performance [47], [49].

A. A Multimodal, Multilayered Monitoring and Control Framework

In Appendix A, we review fundamental modeling for managing complex electric power networks over broad ranges of operating conditions and equipment status. The modeling is structure-based, and it represents an outgrowth of a structure-based modeling approach initially developed for the enhanced operation of electric power grids during normal conditions [13], [20], [21]. In this section, we propose a decision-making approach based on these models. The approach uses the formalized hierarchical models to explicitly monitor and ensure through adaptive control a *predictable* response of the closed-loop interconnection dynamics. The novel aspect of this approach is that, even when the system does not exhibit such response without enhanced control, the control is adapted to ensure such response.

Predictable system response conditions are conceptually ensured in several steps: (0) on-line monitoring of the status of the QIs relevant for detecting modal changes; 1) by enhancing the logic of the local equipment controllers [38] by stabilizing system dynamics as the properties of QIs change in a qualitative way; and 2) by adaptively changing on-line the settings of the equipment controllers, in order to re-direct the existing resources as the operating conditions vary outside the acceptable ranges. At the subsystem (control area) level and the interconnection level QIs introduced in Appendix A are used to monitor how far these are from their values specified for normal conditions. As the QIs approach the threshold of their normality, the basic monotonic system assumptions cease to hold. The QIs effectively become precursors of abnormal conditions. The status of the QIs becomes, in turn, an indicator that the logic of primary controllers needs to be adjusted in order to induce a closed-loop monotone response of system dynamics. The transition from normal to less normal conditions and the control adaptation are fairly seamless both in time and space.

The multimodal features are as follows: As long as the status of the QIs is such that the currently implemented hierarchical control is effective, the system operations and control resemble current practices. However, as conditions vary, for a variety of triggering causes, the QIs are monitored and used to re-schedule the other resources and keep the interconnection as close to normal as possible by means of hierarchical control. An illustration of using QIs for enhancing reliability on-line over the broad ranges of power transfers is given in Section VII. A major open R & D question concerns the development of effective algorithms for relating properties of QIs, with the procedures currently used by the power system operators for deciding on various levels of operational severity.

The following are basic essential steps for an enhanced control design which builds upon today's hierarchical control. Its objective is to support on-line monitoring and control for enhanced reliability with provable performance as defined in the Section VI.

- Define bounds on disturbances (demand deviations and/or classes of equipment failures) for which control is expected to ensure a reliable performance.
- Formulate limits on control (actuators).
- Design a multirate state estimators for providing the information about the type of operating ranges for which the quasistationary control (scheduling) and stabilizing feedback are needed.
- Use the information from the state estimators to automate on-line corrective actions for optimizing the use of available controls.
- Use the information from the state estimators to adjust the control logic of the primary fast controllers on individual pieces of equipment (power plants, transformers, and transmission lines in particular).
- Use the information from the state estimators on a slower time scale to adjust the constraints on the output variables so that the system stabilization is ensured as the system is optimized in a quasistationary way [39].

B. *The Key Role of QIs as the Precursors of Abnormal Operations*

We close by observing that steady-state and small-signal stability are ensured for the operating points satisfying the qualitative indices (QIs)' normal status; the QIs are characterized for the closed-loop dynamics and, therefore, depend fundamentally on the control logic implemented. For example, the system Jacobian defining small-signal dynamics depends, among other factors, on the control logic of the fast primary controllers. Keeping this in mind, it becomes possible to take a pragmatic approach to ensuring stable operations over broad ranges of operating conditions in two steps, namely by 1) identifying the basic nature of the system QIs; and 2) by sending signals to the primary controllers to adjust their logic as the system approaches ranges where the QIs may change their normal status unless this adjustment is done. The role of QI characteristics as the qualitative precursors of instability has been studied to a lesser extent in the context of continuous dynamics. Analogous qualitative precursors have been studied more extensively in the context of potential mid-range voltage instabilities related to the malfunctioning of OLTCs and their implications on some early voltage collapse-related blackouts [30], [36].

It is essential that we make progress toward computationally manageable precursors for on-line detection of abnormal QIs. Questions concerning the reduced information we have for detecting this abnormality are essential to resolve, yet very little progress has been made in this overall area. A particularly challenging task here comes from the change in the QIs' characteristics due to control saturation.

A qualitative change in control logic is also needed for enhanced switching of OLTCs and capacitor banks when system conditions are transiently stable but statically unstable [36].

C. *The Key Role of High-Gain Power-Electronically Switched Controllers*

Given the enormous challenge of one's inability to characterize the regions of abnormality, operating complex power systems in hard-to-predict, not well-understood operating regions raises basic questions concerning the ability of current electric power system to survive instabilities of various types. The basic potential of fast power electronically switched control is significant, provided the control design is carried out systematically. Adding fast network control is essential because most of the existing primary controllers are too slow to stabilize the system dynamics outside normal operating ranges. The slowest control available in power plants which might be candidates to stabilize the system are the field excitation and the valve position. Given that neither of these controls directly affects the electromechanical dynamics of generators (swing equation), the only way for these controllers to stabilize the electro-mechanical variables to keep generators in synchronism, is to apply the high-gain field excitation control [40] and/or the fast valving control

[41]. This further means that the closed-loop dynamics, when affected by the high-gain controllers, is no longer time-scale separable, and the control design becomes more complicated. An example of such inadequate control design of AVRs has been known for quite some time [10]. This has led to the need to introduce enhanced field excitation control by designing PSS control; the PSS control design offers truly enhanced control because it responds to both electromagnetic and electromechanical variables and their rate of change, rotor acceleration in particular.

Further enhancements of field excitation control have been designed which recognize the nonlinear nature of the power system dynamics. In particular, several nonlinear control techniques have been tried and compared for their performance in [44] and [45]. In [44], a comparison of several nonlinear control methods for transiently stabilizing the system when constant gain control, including the conventional PSSs, fails to achieve this, is carried out. The effectiveness of these methods depends on how the total system energy is managed during difficult transients. The potential benefits of such a control design are illustrated in Section VII.

We mention important technological breakthroughs for fast stabilization of transient dynamics which are not traditional generation control means. These technologies are commonly referred to as FACTS [7]. They offer previously unavailable means of stabilizing dynamics by fast power-electronic-based switching, which control how much of the series- and/or shunt- capacitances and inductances are connected to the system. Without going through a detailed treatment, we suggest that, for any of these controllers to transiently stabilize system dynamics, it is necessary that they be fundamentally high-gain.

Similarly, fast load control, in addition to generally un-modeled self-stabilizing load effects, would require high gain feedback as well. The R & D in support of high-gain control on generators, transmission system and loads represents a major opportunity and a major challenge. An ultimate vision for making the existing ac power system "all dc" by distributed high-gain compensation is described in [46] and [56]. The trade-offs between the benefits from such control, costs and risks must be carefully studied. The power-electronic-based transmission and load control via FACTS is fundamentally a switched-mode control and, as such, lends itself naturally to the robust sliding-mode implementations of several key high-gain nonlinear controller types. This indicates a major potential for implementing FACTS technologies systematically.

Finally, we use the example of sliding mode control design to bring up another major challenge. Defining the best sliding mode surface, i.e. the surface to which the dynamics should be stabilized during large disturbances, remains largely an open problem for large-scale systems such as the electric power systems. It was shown in [38] how the choice of postfault equilibria or sliding surface, combined with feedback linearizing controller (FBLC), greatly outperforms the same nonlinear control without careful choice of postfault surface. This development builds upon the early concepts of observation decoupled state space for electric power systems [52]. Once more, one observes that transient stabilization without careful steady-state equilibria choice may not be as effective as it may be possible. Most generally, a sliding mode approach to transient stabilization lends itself well to the problem when constant-gain controllers fail to work.

VII. Illustrative Examples: Possible Means of Enhanced Reliability for the NPCC System

In this section, we use an equivalenced system of the NPCC region in the Eastern United States to illustrate concepts introduced throughout this paper. We start by illustrating a loss of feasible steady-state solution as the increase in power transfer from PJM to Ontario via NY is simulated. During the blackout this increase was caused by the re-distribution of power flows due to the loss of some key transmission lines outside the NPCC system [1], [3]. We then show the sensitivity of the maximum power transfer across this interface to the type of information available to the control areas in this region. It is shown that a feasible transfer across control areas is generally much higher if all control areas adjust to the changing conditions by re-scheduling their real and reactive power support, than it is without the adjustments of the additional resources as the transfer is attempted.

We next illustrate the critical role of high-gain stabilizing control in preserving system integrity as a large power transfer is attempted. A hypothetical situation is simulated showing the effects of a large nuclear power plant causing interarea oscillations between NY and NE power plants with the constant-gain standard AVRs. This response is compared to the response with an adaptive high-gain feedback-linearizing controller. It is shown that such a controller basically preserves the integrity of the eastern and western parts of the NY control area. All conditions being the same in this example, the NY system is transiently unstable with conventional constant gain controllers. It is further shown that this particular controller design could be implemented in a fully decentralized way without requiring additional fast communications. Only the control logic needs to be enhanced relative to what is in place today.

The scenarios presented may or may not be directly related to the most recent events. However, they do demonstrate the tremendous potential of enhanced automated control in keeping the system reliable over broad ranges of operating conditions caused by either wide variations in power transfers across one's control area and/or by the equipment outages.

A. *Dependence of Interconnection Transfer on Scheduling Practices*

Analysis of the NPCC's equivalent system [34] shown in Fig. 5 reveals a tremendous dependence of power transfer feasibility from PJM to Ontario via NY on the specific ways the real power and voltage are dispatched. To start with, during normal conditions documented in [34], the power transfer from PJM (Alburtis in Fig. 5) to NY is 895 MW for the nominal power dispatch, prescribed voltages and

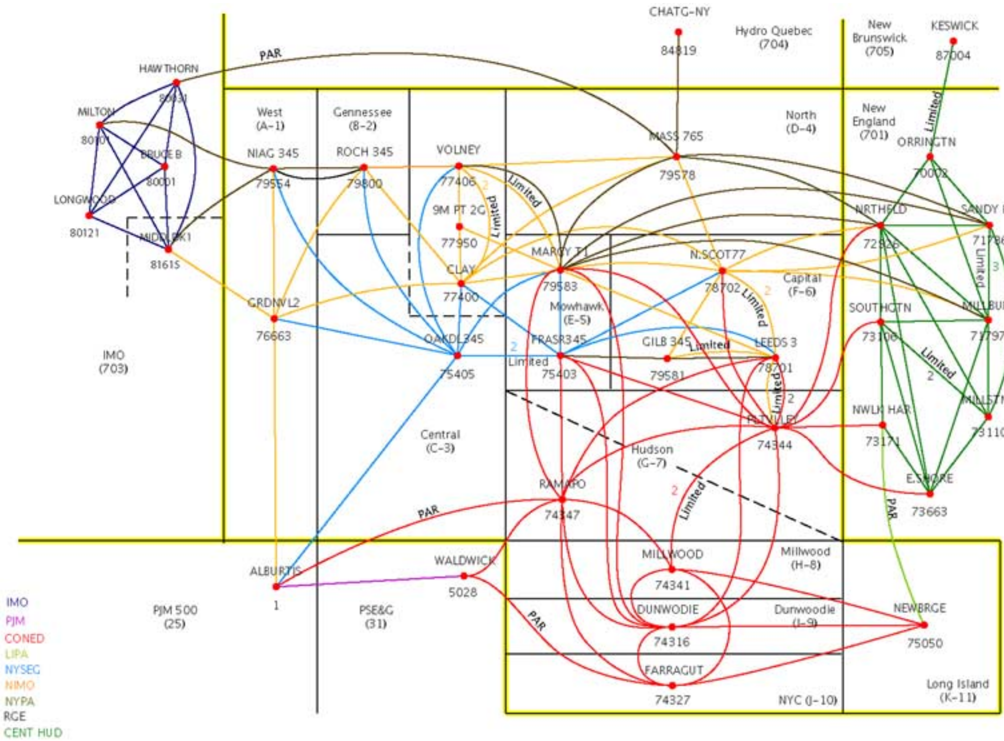

Fig. 5. One-line diagram of the equivalenced NPCC system.

fixed flows on lines equipped by the PARs (denoted as PAR lines in the NPCC diagram.) There are four PARs in this system, two between PJM and NYISO, and one PAR between NYISO and IMO. The current operating practice is to maintain the flows through the PAR-controlled tie-lines at their fixed values during normal operations, and to allow for maximum transfer during emergencies[9] In order to analyze how the transfer across NY area is affected by power scheduling inside NYISO and also by the real power flow schedule via PARs between the control areas, we consider several effects in what follows.

Effect of Real Power Scheduling Inside New York: Here, we consider three scenarios:

- Base planning Case #B for given 2002 transmission system and the 2007 summer peak projected load as described in [34].
- Case #1 is the same case except the entire available real power generation was re-scheduled in order to support an increased wheel from Alburtis to NYISO, through NYISO to IMO into Milton (bus #80 101). This is potentially a situation resembling the August 2003 blackout situation when a great deal of power was being transferred from PA to the Southern Ontario area in order to balance outside shortages. This case is simulated to show the potential effect of the coordinated rescheduling of resources to support the necessary power transfer.
- Case #2 is the same as Case #1 except the power from PJM is injected into Waldwick (bus # 5028) and not into Alburtis. The power is taken out at Milton (bus # 80 101). A comparison of Cases #1 and #2 is made to illustrate that when the system is close to its feasibility limits the actual point of injection may make a difference in how much total net power is feasible to transfer across the same interface.

The optimal scheduling of available real power in NYISO in support of the desired wheel was computed so that transmission losses are minimized using NETSS software [42], [53], [54]. It was found that in Case #1 it would be possible to inject total of 1200 MW into Alburtis. It was found that with the same real power generation available in NYISO in Case #2 it would only be possible to transfer less than 100 MW from Waldwick to NYISO. An important side observation here is that it definitely matters at which node the power is injected. This points to the need for specifying more than currently used net power transfer between the two control areas.

Effect of Phase Angle Regulators (PAR) Scheduling of the Tie-Line Flows Between the Control Areas: The same three cases are considered here, while allowing PARs to schedule flows within their maximum capacity limits. It was found that for Case #1 real power rescheduling of resources would enable a power transfer of 8800 MW.[10] In the case of power injection into Waldwick, Case #2, the biggest wheel possible is only 500 MW without rescheduling real power inside NYISO. This means an increase of about 400 MW from Waldwick. An important observation concerning

[9]There have been recent efforts to adjust PAR settings between NYISO and PJM according to market needs.

[10]The results here are only for illustrative purposes as they are inspired by the recent blackouts. However, the equivalenced NPCC model used does not account for several key interface limits internal to PJM, because of the coarse system representation.

PARAs' settings is that these require coordination among the control areas.

Effects of Voltage Scheduling in Support of Higher Power Transfers: An experiment was carried out starting with no wheel beyond the base load conditions. The largest feasible wheel, given the maximum PAR scheduling possible, without real power re-scheduling and given fixed nominal voltage [34], was assessed. The highest feasible wheel into Alburtis and out of Milton was 1200 MW, and 500 MW into Waldick. With the voltage schedule optimized within $+/-.03$pu range around the nominal voltage, without any real power re-scheduling the maximum transfer increased to 2900 MW into Alburtis and to 2900 MW into Waldwick, respectively. Moreover, with the voltage optimized within $+/-.05$pu the feasible wheels increased to 3100 MW at both Alburtis and Waldwick. The feasible range decreased at Waldwick even with the voltage support of $+/-.05$pu without PAR-based real power re-scheduling of flows to 2300 MW. Finally, with both voltages optimized within $+/-.05$pu and the real power re-scheduled by the NYISO, the maximum wheel possible is around 8800 MW.

For an illustration of the NPCC system response to the outage of PJM transmission line connecting Alburtis to Waldwick, see [42]. In this paper, an eigenanalysis of the NPCC system is presented documenting that this system is close to having almost singular Jacobian. Detailed illustrations are provided showing: 1) the feasibility limits of the NPCC system during this outage; 2) the dependence of results on coordination between interconnected control areas to the PJM area in which the fault has occurred; 3) the dependence of the transfer capability of the system as a whole on the control rules in place for PARs; and 4) the dependence of simultaneous feasibility conditions on the voltage dispatch in support of necessary power transfers. While these results do not necessarily represent the actual events of August 2003, they are used to illustrate the potential of on-line coordination prior to the conditions when the system stability is affected.

B. *Potential of Novel Stabilizing Controllers for Preserving System Integrity*

A major goal in the research of FBLC control carried out some time ago was to explore the potential of using more advanced control as a method of stabilizing the power system when it is operating under conditions that are conducive to poorly damped multimachine oscillations [38], [44]. A 38-bus, 29–machine equivalent model of the NPCC system, covering New York State and parts of the New England and Canadian systems, was developed by the New York Power Pool, specifically for development work toward damping multimachine oscillations that have been noted in that system. The main objective in developing the model was to adequately reproduce a multimachine oscillation that occurred at approximately 0.75 Hz, involving groups of machines in the New York City area (modeled primarily by the Sprainbrook generator) and the northeastern part of New York State, as well as parts of the Canadian power system (modeled primarily by the Oswego and Chateauguay units, although others also participated). The NPCC equivalent model consists of a 38-bus transmission network supporting

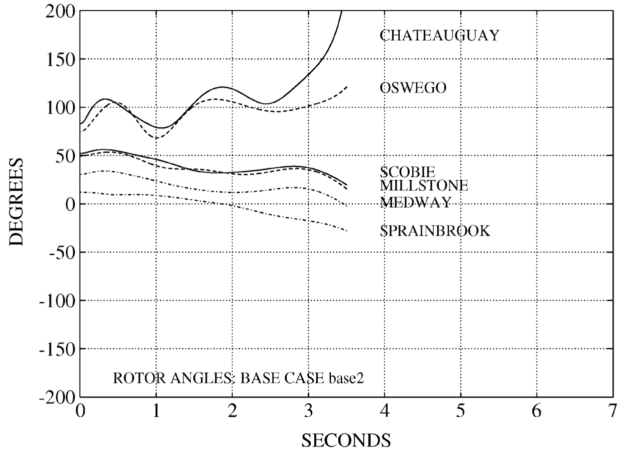

Fig. 6. Base case for Selkirk fault.

15 fully modeled synchronous generators (sixth-order model) and 14 second-order "swing model" generators, represented as a constant voltage behind the transient reactance, with a constant power input and an equivalent rotating inertia. Also included in the model were two static VAR compensators. The 15 detailed machine models also included full exciter dynamics, ranging from IEEE Type 1 through IEEE type ACx and STx, some including a PSS. Most of the excitation models conformed to the IEEE standard types; however, some custom configurations were also used, specifically in the Bruce complex equivalent in Ontario, Canada, which also included a nonstandard PSS. The other PSS models were IEEE standard. It should be emphasized that all of the equipment names used in describing the simulations are taken from the NPCC system, but are used here to conveniently refer to the equivalents used in the reduced model. The fault scenario selected for this series of tests was a five-cycle three-phase short circuit on the Selkirk equivalent bus, followed by the removal of the Selkirk/Oswego transmission line from service. This line represents a large fraction of the transmission from the northwest to the southeast region of New York, carrying 1083 MW in this scenario. In the base case, this sets up an oscillation at approximately 0.75 Hz, involving the Oswego, Chateauguay and several other units. The oscillation grows until the Chateauguay generator loses synchronism, followed shortly by the Oswego unit.[11]

Shown in Fig. 6 is the response of critical variables during the Selkirk fault. It can be shown that the instability occurs after a couple of swings.

Shown further in Fig. 7 are voltages around the Central East area of NY system, corresponding with the Selkirk fault. It can be seen that the voltages oscillations are fairly severe.

Shown in Fig. 8 is the rotor angle plot from the simulation of the FBLC control where three units have the FBLC control. It can be seen that this controller is actually controlling two recognized interarea modes, one north-to-south

[11]This oscillation has not been seen much lately, since the construction of a big combined cycle plant and, because of this, the presented results may be more illustrative in nature than directly applicable to the current system situation.

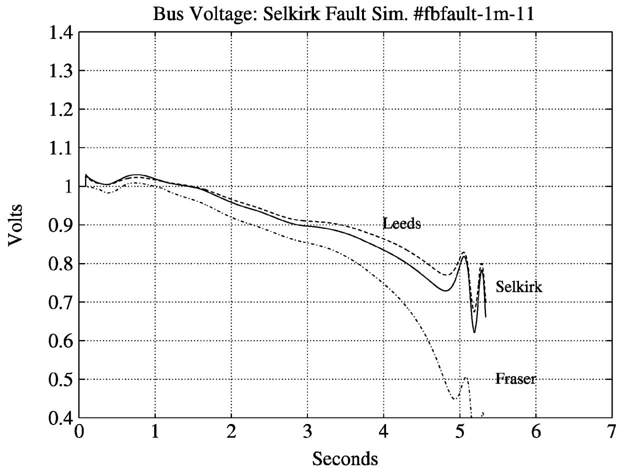

Fig. 7. Base case voltages during the Selkirk fault.

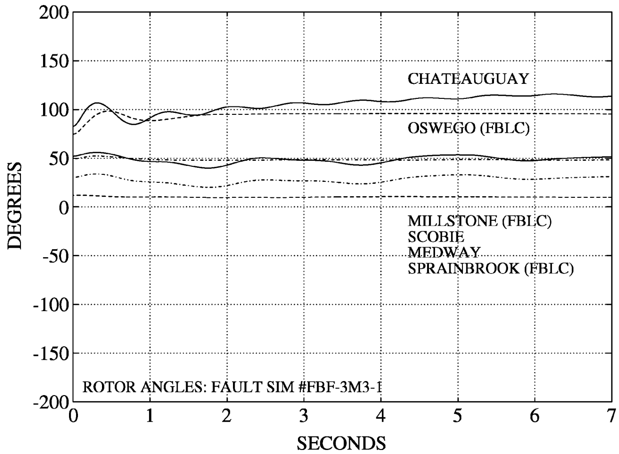

Fig. 8. Rotor angle response with advanced FBLC controller.

at 0.7 Hz, another east-to-west at about .35 Hz. The second mode is of particular interest because it has been seen in operations but was never captured in the reduced model.

Similarly, shown in Fig. 9 are bus voltages at Central East with the FBLC control implemented. It can be seen that these are fully stabilized.

A more detailed description of the potential for stabilizing the NPCC system during the large faults when the conventional controllers fail to do so can be found in [38] and [44]. This is just one example of a possible enhancement by means of more adaptive stabilizing controllers, in the area directly affected during the August 2003 blackout. It may be beneficial to pursue further R & D toward further implementation of such devices. They are inexpensive and do not require any system-wide adjustments nor communications. The potential for enhancing reliability through stabilization may be significant.

VIII. Conclusions

This paper concerns the enormous complexity of operating today's electric power systems on-line over broad ranges of conditions. It recognizes that specific current state-of-the-art methods exist for modeling, analyzing and

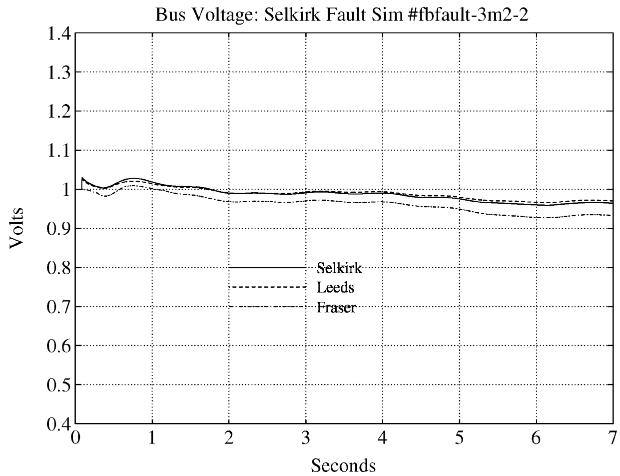

Fig. 9. Voltage response with advanced FBLC controller.

designing decision and control tools for managing particular subtasks, under strong, often implied, assumptions about how the other tasks are being performed. This collection of methods with various implied assumptions does not readily lend itself to a methodology necessary for supporting operations of complex real-life electric power interconnection.

Similarly, the paper recognizes that current operating practices by the utility system operators work well over the range of conditions for which they were tested and prescribed. These practices have evolved over time. However, as the electric power interconnection has grown in its complexity, the bottom-up practices and assumptions about the rest of the system specific to the individual utilities are being challenged when the assumptions under which the local practices were established no longer hold.

Correcting for this fundamental lack of the overall methodologies, theoretical and practical, managing the large electric power grid of today is often attempted in an off-line mode of planning for the worst case scenario in larger portions of the interconnections, such as power pools, and industry governance at large. These efforts are necessary and are helpful for establishing basic planning guidelines (industry standards). However, these guidelines do not necessarily map into on-line procedures, automated and/or human-operator-assisted, for predictable system performance as the operating conditions in the entire interconnection vary. It is this basic lack of methodology for integrating current operating practices within each utility and among utilities in an on-line mode that from time to time results in highly unacceptable performance. It is the lack of easy-to-use quantifiable means of assessing the vulnerability of the system as the system configurations and conditions vary, which generally results in: 1) a suboptimal performance, concerning the overall use of resources; and/or 2) catastrophic failures to serve a large number of users over a prolonged time.

In order to overcome these fundamental problems, this paper presents a multilayered multimodal framework for operating electric power systems over broad ranges of conditions by means of automated control. We suggest that the approach is a natural next step beyond the currently used hierarchical control, and would not be a radical experiment. The technological challenge is analogous to the one faced some time ago when the first experiment of flying by wire was pursued. The paper provides a somewhat detailed comparison of how and why the two operating modes (normal and abnormal) present a qualitatively different challenge to the general state-of-the-art automatic control of large-scale complex dynamic systems. Very similar to the challenge of dynamic control of aircraft over broad ranges of modes, one must accept that the system might be on the boundary of stability prior to equipping it with the right feedback. Also, the same as with automated flying, one of the major challenges to R & D is in the area of developing reliable and flexible software in support of such stabilization. Such a lack of reliable software played a key role in the August 2003 blackout. Systematic integration of various modeling and decision tools for managing the system over vastly different time horizons and with vastly different levels of spatial detail is essential. Redundant systems for navigating the power grid over broad ranges of conditions are also seen as necessary for making the framework fault-tolerant with respect to control failures. We offer our vision for navigating future electric power systems to a larger extent by wire, and to a lesser extent by human operators. Finally, we summarize the relevance of more adaptive system control for the evolving industry structures.

The August 2003 blackout scenario is used to illustrate what might happen if enhanced automation were used in response to the same root cause failures. This is illustrated using the 36-bus equivalenced NPCC power system, which represents a significant portion of the Eastern Interconnection of the United States.

We stress that as the complexity grows, the challenge to the control design for operating the system within given specifications also grows. Nevertheless, as long as specified properties of certain QIs are met, the complexity is still manageable in a hierarchical way to ensure the reliable service of the entire interconnection. Most importantly, the basic nature of the QIs can be changed by closed-loop high-gain primary control.

We close by emphasizing that there is a very real danger of moving toward automation without recognizing that the effects of uncoordinated control could easily induce damage over extremely far electrical and geographical distances. The ideas presented in this paper could do more harm than good unless a serious effort is put into the development of new online analysis tools to make adaptive systems work. In addition, it is essential to pursue development of pragmatic robust tools for very large-scale systems within a predictable accuracy.

Appendix A. An Electric Power System: Functions, Dynamics, and Control

In order to understand temporal and spatial interdependencies in large electric power interconnections, it is important to understand the basic models underlying hierarchical operation during normal conditions. Unfortunately, currently used models are specific-purpose-oriented, and do not lend themselves to an intuitive understanding of changes and their effects as the system conditions vary. In order to overcome this, we present here a structure-based general model first. This model is then used to show how current models for hierarchical control under normal conditions are derived and the underlying assumptions. These assumptions are often implied and reflected in the human experts' knowledge about the system. The presented derivation makes these explicit, and helps one understand the role of control design in ensuring that these conditions hold as operating conditions vary. The same model is used to introduce and illustrate the relevance of QIs in a horizontally structured (multiarea) interconnection for monitoring if and when the areas need coordination for reliable service.

A. Structure-Based Coupled Real Power/Voltage Dynamics in a Multiarea Interconnection

Consider without loss of generality the interconnected electric power network shown in Fig. 2 [13]. Loads at the buses in the system are denoted as L_i and the power plants as G_j. Fig. 2 is a one-line diagram representation of a three-phase transmission system interconnecting the two subsystems of the system. The circled areas represent horizontally structured utilities within this network. The basic objective of this system is to deliver power generated to its time-varying loads so that frequency and voltage remain nearly constant as load varies. Because there is very little storage, the supply and demand must balance almost instantaneously. During normal conditions a feed-forward scheduling of electric power is performed to supply forecast demand. Unless it is otherwise specified, the known (forecast) portion of the load is represented as a constant real power constant reactive power sink. Bulk-level load is hard to model accurately because it is an aggregate of many small loads of nonuniform types. Moreover, the real power demand is fairly predictable. The reactive power load is much harder to know with high accuracy; because of this, it is much harder to use reactive power resources adequately. Load deviations from forecast are compensated for by automatic adjustments of real power produced to correct for frequency changes, and by AVRs, responding to voltage deviations caused by the deviations in reactive power demand from the assumed reactive power demand. During normal operating conditions the status of all equipment, both transmission lines of the interconnected network and the power plants, is as planned.

For the purposes of introducing a general structure-based model, we start by recognizing that any electric power system can be thought of as consisting of generators locally controlled and interconnected to the loads through a transmission network, as shown in Fig. 4.

As shown schematically in this figure, local generator controllers are governors controlling mechanical power deviations P_{mj} produced by the prime movers in response to frequency ω_j around the set values $\omega_{Gj}^{\mathrm{ref}}$ and excitation systems controlling field voltage deviations $e_{fd,j}$ in response to the deviations in terminal voltage (magnitude) from the set value $V_{G,j}^{\mathrm{ref}}$. The relevant output variables on the generator side affecting the transmission network and the loads are real electric power $P_{G,j}$, reactive power $Q_{G,j}$, frequency $\omega_{G,j}$ and terminal voltage $V_{G,j}$. The $P_{L,i}$, $Q_{L,i}$, $\omega_{L,i}$ and $V_{L,i}$ are the corresponding variables at the load bus. During the normal operating conditions governors and excitation systems respond automatically to fast load fluctuations. The turbine (prime mover)--generator sets have their own dynamics of producing $P_{G,j}$ which combined with the governor and excitation dynamics defines what is known as the (local) primary dynamics of the governor-turbine-generator (G-T-G) sets.

Load Characterization: Loads are often assumed not to have significant inertia, and are typically modeled as sinks of prespecified real and reactive power [8]. The major load component is being forecast on daily basis and power is scheduled to supply this component. Shown in Fig. 3 is a typical load pattern. For purposes of this paper the real power load is modeled as

$$P_{L,i} = P_{L,i}(t) + P_{L,i}[k] + P_{L,i}[K] \tag{1}$$

and the reactive power load as

$$Q_{L,i} = Q_{L,i}(t) + Q_{L,i}[k] + Q_{L,i}[K] \tag{2}$$

The slower components of the real and reactive power load which are assumed to be forecast with high accuracy are denoted by $P_{L,i}[K]$ and $Q_{L,i}[K]$, respectively, and are denoted in Fig. 3 as being estimated each $[KT]$ interval, where T represents days, hours or 15 minute time samples. The components $P_L[k]$ and $Q_L[k]$ represent minute-by-minute load deviations around this forecast (nominal) demand component. Finally, $P_L(t)$ and $Q_L(t)$ represent very fast, presumably very small amplitude, load deviations around the minute by minute deviations. Both minute-by-minute and instantaneous load deviations are viewed as disturbances whose effects are regulated and stabilized in a feedback-manner.

It is also important to keep in mind that power consumed by various loads will vary with the frequency and voltage deviations; in this sense loads are self-stabilizing by reducing their own power consumption with the reduction in voltage and frequency. While this effect is not negligible, it is rarely modeled simply because it is too hard to do at the bulk transmission level where loads are aggregates of many physical loads of nonuniform types at the distribution level. One relevant observation is that when the system is close to breaking up, the outcomes may be very sensitive to the load representation. However, since the highly accurate load representation is problematic, it is critical to have operating practices in place which are robust with respect to load model inaccuracies. We believe that this lack of actual load models has been one of the major reasons for not relying more heavily on real-time control.[12]

Generator Dynamics and its Fast Voltage Primary Control: A generator G_j can be thought of as a combination of two subsystems, which roughly represent the mechanical and the electromagnetic aspects of the machine. The mechanical behavior is dominated by the effects of the rotor mass, and unless the torsional behavior of the shaft is to be modeled, it is represented as a second-order subsystem

$$\dot{\omega}_j = \frac{1}{M_j}\left[P_{\mathrm{mech},j} - P_{G,j} - \frac{D_j}{\omega_0}(\omega_j - \omega_0)\right] \tag{3}$$

$$\dot{\delta}_j = \omega_j - \omega_0 \tag{4}$$

The electromagnetic subsystem is coupled to the mechanical subsystem by the energy transfer across the magnetic field in the machine air gap. In contrast to the mechanical model, there is wide variation in the way the electromagnetic subsystem is modeled, depending primarily upon the time scale at which the phenomena of interest occur. The dynamic model

$$\dot{E}'_{di} = \frac{1}{T'_{q0i}}\left[-E'_{di} + \left(x_{qi} - x'_{qi}\right) i_{qi}\right] \tag{5}$$

$$\dot{E}'_{qi} = \frac{1}{T_{d0i}}\left[-E'_{qi} - \left(x_{di} - x'_{di}\right) i_{di} + e_{fdi}\right] \tag{6}$$

provides good agreement for the behavior of the synchronous generators over a time scale of perhaps 20 s following a disturbance. Electromagnetic transients that occur over fractions of a cycle to several cycles are assumed to have stabilized, while longer-term dynamics are assumed to be substantially constant on this time horizon. In particular, most large generating units are not equipped to effect large changes in the input power which the prime mover supplies to the generator itself. Therefore, for short-term simulations, the input torque is usually considered to be constant. The mechanical variables are ω_j and δ_j, representing the frequency and the relative rotor angle of the generator j, respectively. The rotor moment of inertia is M_j, the input torque is $P_{\mathrm{mech},j}$ and $P_{G,j}$ is the electrical power supplied to the transmission system. D_j is a damping term that reflects several different damping effects such as windage, turbine damping and damper winding torques. D_j tends to be small and is often ignored entirely. The quantity $(E'_{d,j} + jE'_{q,j})$ is a phasor representation of the Park-transformed three-phase machine voltage. The direct and quadrature transient impedances are denoted by $x'_{d,j}$ and $x'_{q,j}$, respectively, while $i_{d,j}$ and $i_{q,j}$ are the direct and quadrature projections of the machine armature current, in the machine frame of reference.

[12]As demand-side management technologies are implemented, many loads will become control assets in the system, instead of a disturbance. This may have a major impact in the future performance of the grid.

Denoting the state variables of the $j-th$ generator by $x_j = [\omega_j \delta_j E_{d,j} E'_{q,j}]$, its fast coupled electromechanical and electromagnetic model in (3)–(6) can be represented as

$$\dot{x}_j = \tilde{f}_j(x_j, u_j, y_j, p_j) \tag{7}$$

where u_j is a local (primary) control of generator j if present, and y_j is a local coupling variable through which local dynamics of generator j interacts with the rest of the system. p_j stands for the parameters of a generator j.

A local continuous control u_j is typically designed in response to a local error signal

$$e_j = y_j - y_j^{\text{ref}} \tag{8}$$

Here, $y_j^{\text{ref}} = V_j^{\text{ref}}$ is the set point for terminal voltage of the generator. AVR is a typical local controller which regulates field excitation $e_{fd,j}$ so that the terminal voltage of the generator remains at its set (reference) value [9], Fig. 4. As an example, an IEEE standard AVR is given as [10]

$$\dot{V}_R = \frac{1}{T_A}\left(K_A V_F \frac{K_A K_F}{T_F} E_{fd} V_R K_A \left(E_G - E_G^{\text{ref}}\right)\right. \tag{9}$$

$$\dot{E}_{fd} = \frac{1}{T_e}(K_e + S_e)E_{fd} + V_R \tag{10}$$

$$\dot{V}_F = \frac{1}{T_F}\left(V_F + \frac{K_F}{T_F}E_{fd}\right). \tag{11}$$

When the gains of the AVR in (9)–(11) are too-high, an AVR could destabilize system dynamics [9], [10]. Because of this many modern generators are equipped with PSSs to extend the stability limits. The PSSs model is omitted here, but can be found in [11]. While the eastern interconnection of the US power system does not have very many PSSs, these have been implemented in the western US interconnection and in several other countries throughout the world and have contributed to a significant enhancement of system stabilization.

Finally, for the purposes of introducing the general structure of an interconnected electric power system, we represent the local structure of the generator electromagnetic dynamics (5)–(6) and its AVR controller dynamics as (9)–(11)

$$\dot{x}_{LC,j}^Q = f_{LC,j}^Q\left(x_{LC,j}^Q, y_{LC,j}^Q, y_{LC,j}^{Q,ref}, p_{LC,j}^Q\right) \tag{12}$$

where $[x_{LC,j}^Q = [E_{dj}\ E_{Qj}\ V_{Rj}\ e_{fd,j}\ V_{Fj}]$ and $y_{LC,j} = i_{qj}\ i_{dj}\ V_{Gj}]$. A generalized linearization of this local dynamics over the ranges of operating conditions takes on the form

$$\dot{x}_{LC,j}^Q = A_{LC,j}^Q x_{LC,j}^Q + C_j^Q i_{dj}. \tag{13}$$

Governor-Turbine-Generator (G-T-G) Dynamics and its Primary Frequency and Voltage Control: A G-T-G set represents adjustments of mechanical power of the prime mover $P_{\text{mech},j}$ so that the variations in demand from its forecast are compensated for. In general, the complexity of the governing equations varies depending on the type of prime mover. Combining the mechanical dynamics of the generator (3)–(4) , with the turbine dynamics

$$\dot{P}_{\text{mech},j} = \frac{1}{T_{u,j}} n_j(P_{\text{mech},j}, a_j) \tag{14}$$

and with the governor dynamics

$$\dot{a}_j = \frac{1}{T_{g,j}} m_j\left(a_j, \omega_j, \omega_j^{\text{ref}}\right) \tag{15}$$

where $T_{u,j}$ and $T_{g,j}$ are the time constants of the turbine and the governor results in a closed-loop dynamic model of a G-T-G set. The mechanical variable of the generator is its frequency ω_j, the state variable of the turbine is $P_{\text{mech},j}$, which corresponds to the part of the mechanical power directly regulated by the valve opening a_j, which is a state variable of the governor in its closed-loop operation.

With a local controller of the above form, the closed-loop local dynamics of a generator connected to bus j takes on a general form

$$\dot{x}_{LC,j}^P = f_{LC,j}^P\left(x_{LC,j}^P, y_{LC,j}^P, y_{LC,j}^{P,ref}, p_{LC,j}^P\right) \tag{16}$$

A generalized linearization of this model over a broad range of conditions of interest takes on the form

$$\dot{x}_{LC,j}^P = A_{LC,j}^P x_{LC,j}^Q + C_j^P P_{Gj} \tag{17}$$

Here, $y_{LC,j}^{P,\text{ref}} = \omega_j^{\text{ref}}$ is the nominal set point for the frequency speed changer.

Network Constraints: For frequency ranges of interest in normal operating conditions the network is modeled as an algebraic (vector) constraint imposed on generator and load outputs.[13] During normal operations the most uncertainty is seen in load models. Because demand consumption is specified in terms of its real power P_L and reactive power Q_L, the network constraints are expressed in terms of nodal-type equations that require complex-valued power into the network $\hat{S}^N$ to be equal to the complex-valued power $\hat{S} = P + jQ$ injected into each node,

$$\hat{S}^N = \text{diag}(\hat{V})\hat{Y}_{\text{bus}}^* \hat{V}^* = \hat{S} \tag{18}$$

[13]For some highly abnormal situations, close to voltage collapse scenarios in particular, this model may not hold [12].

where $\hat{S}^N = P^N + jQ^N$ is the vector of transmission network line flows into all nodes and $\hat{Y}^*_{\text{bus}}$ is the admittance matrix of the network [13]. $\hat{V}$ is the vector of all nodal voltage phasors with magnitude E and angle δ.

The real part of (18) has the structure

$$P^N = P^N(\delta, V) \tag{19}$$

Furthermore, the real power injected into each generator terminal on the interconnected system is the sum of the generator power output P_G and the real power flow from the neighboring control areas F_G, that is $P = P_G + F_G$. With this, the real power network constraint on the interconnected system takes on the structural form of interest as

$$P^N_G(\delta_G, \delta_L, V_G, V_L) = F_G + P_G. \tag{20}$$

Similarly, since the real power from the load into the network can be written as the difference of real power injected at the load bus F_L and the real power absorbed by the load P_L, the network constraints at the load buses are expressed as

$$P^N_L(\delta_G, \delta_L, V_G, V_L) = F_L - P_L. \tag{21}$$

This separation of the power injection P into the part resulting from the intraarea injections P_G and the part from the interconnecting tie lines with the neighboring control areas F_G is essential for structure-based medelling of horizontally divided subnetworks. The term "structure-based" is used to emphasize that variables directly relevant for various hierarchical levels can be expressed explicitly in terms of variables at each specific level [13].

Similarly, the imaginary part of the power balance (18) are of the form

$$\text{diag}\left(\frac{1}{V_{G,j}}\right) Q^N_G(\delta_G, \delta_L, V_G, V_L) = F_G + i_d \tag{22}$$

and

$$\text{diag}\left(\frac{1}{V_{L,i}}\right) Q^N_L(\delta_G, \delta_L, V_G, V_L) = F_L - i_L \tag{23}$$

for generator and load buses, respectively [13].

Nonlinear Differential-Algebraic Dynamic Model of a Control Area: Combining the closed-loop dynamics of all generators inside a control area (16) and (12) with the network flow constraints (20)–(23), generally results in a coupled set of nonlinear DAEs of the form

$$\dot{x} = f(x, y, y^{\text{ref}}, p, d) \tag{24}$$
$$0 = g(x, y, y^{\text{ref}}, p, d) \tag{25}$$

where x are state variables defining system dynamics of all system components (such as power plants and their control) and y are coupling variables (such as power flows or current flows) in the transmission lines. System parameters, such as forecast demand, inertia and damping of power plants, are represented as a vector p. Vector d represents system disturbances, such as deviations in real and reactive power demand in (1) and (2).

This model is generally of very high order for a typical control area or a region. Variations of this model have been used for extensive off-line stability studies [14]. Simulations have been done for what is viewed to be the worst case scenario caused by large equipment failures. Each operator knows the system well, and, for the ranges of loading and export/import conditions allowed has a list of such scenarios. The basic approach to analyzing the stability of large utility systems has largely been based on numerical integration approaches. While some progress has been made toward dynamic security assessment methodologies, the problem of near real-time transient stability analysis remains largely an unsolved problem for a variety of reasons, including fundamental DAE numerical integration problems [15], [16]. One pragmatic approach to analyzing the system as the conditions change is based on various learning methods [17], [18].

This paper is, however, not concerned with modeling for system analysis itself. It concerns itself, instead, with models and methods for on-line decision making and control design capable of keeping the service reliable. This, in turn, requires posing the decision-making and control problem explicitly. One such limited formulation can be found in [19]. In Section III, we have further formalized this problem formulation.

B. A Structure-Based Coupled Nonlinear Real Power Voltage Dynamics Model

As explained earlier in this paper, there is not much one could do in terms of formalizing control design for dynamic systems characterized as DAE models. To overcome this fundamental problem, we introduce a structure-based nonlinear model specific to electric power systems which is in a standard-state-space form of ODEs that lends itself to the well-established control design thinking. Of course, the simplification from a general DAE model to a nonlinear ODE model is not always justifiable. One possible approach is to monitor indicators under which this simplification is possible. We refer to these as the qualitative indices (QIs) because they exhibit qualitative properties of interest over a range of conditions. As long as all QIs are such that this simplification is possible, namely the QIs are normal, a simplified nonlinear ODE model is used to adjust controller gains for guaranteed performance. Depending on the characteristics of the nonlinear ODE model, new, lower layer, QIs are defined which make it possible to further simplify control actions.

The first step here is to attempt a simplification from a general DAE model (24)–(25) to a nonlinear ODE model. One way of achieving this is to directly differentiate (20)through (23), solve from (21) and (23) for $[\dot{\delta}_L \dot{V}_L]$ and substitute into (20) and (22). This results in the following model:

$$\begin{bmatrix} \dot{P}_G \\ \dot{i}_d \end{bmatrix} = [\epsilon_1 0] \begin{bmatrix} x_{LC}^P \\ x_{LC}^Q \end{bmatrix} + [0 \epsilon_2] \begin{bmatrix} \dot{x}_{LC}^P \\ \dot{x}_{LC}^Q \end{bmatrix} + \gamma \tag{26}$$

with E_1 and E_2 relating $\omega_G = E_1 x_{LC}^P$ and $e_q' = E_2 x_{LC}^Q$,

$$\epsilon_1 = \left(J_3 - J_4 J_2^{-1} J_1\right) E_1 \tag{27}$$
$$\epsilon_2 = \left(J_3 - J_4 J_2^{-1} J_1\right) E_2 \tag{28}$$

Matrices J_1, J_2, J_3 and J_4 are defined as

$$J_1(\delta, V) = \begin{bmatrix} \frac{\partial P_L}{\partial \delta_G} & \frac{\partial P_L}{\partial V_G} \\ \frac{\partial Q_L}{\partial \delta_G} & \frac{\partial Q_L}{\partial V_G} \end{bmatrix} \tag{29}$$
$$J_2(\delta, V) = \begin{bmatrix} \frac{\partial P_L}{\partial \delta_L} & \frac{\partial P_L}{\partial V_L} \\ \frac{\partial Q_L}{\partial \delta_L} & \frac{\partial Q_L}{\partial V_L} \end{bmatrix} \tag{30}$$
$$J_3(\delta, V) = \begin{bmatrix} \frac{\partial P_G}{\partial \delta_G} & \frac{\partial P_G}{\partial V_G} \\ \frac{\partial Q_G}{\partial \delta_G} & \frac{\partial Q_G}{\partial V_G} \end{bmatrix} \tag{31}$$
$$J_4(\delta, V) = \begin{bmatrix} \frac{\partial P_G}{\partial \delta_L} & \frac{\partial P_G}{\partial V_L} \\ \frac{\partial Q_G}{\partial \delta_L} & \frac{\partial Q_G}{\partial V_L} \end{bmatrix} \tag{32}$$

and

$$\gamma = J_4 - J_2^{-1} \dot{c}_1 - \dot{c}_2 \tag{33}$$

where c_1 and c_2 account for the effects of real and reactive power load demand deviations around forecast, and are defined as derivatives with respect to time of

$$c_1 = \left[\left(F_L - P_L\left(Q_L + F_L^Q\right)\right]^T \tag{34}$$
$$c_2 = \left[P_G F_G^Q\right]^T. \tag{35}$$

The standard state space formulation (in ODE form) of the nonlinear coupled real power/voltage dynamics is obtained by combining (13), and (17), and (26) into

$$\mathcal{I} \begin{bmatrix} \dot{x}_{LC}^P \\ \dot{x}_{LC}^Q \\ \cdots \\ \dot{P}_G \\ \dot{i}_d \end{bmatrix} = \begin{bmatrix} A_{LC}^P 0 C_M 0 \\ 0 A_L C^Q 0 C \\ \cdots\cdots\cdots\cdots \\ \epsilon_1 000 \end{bmatrix} \begin{bmatrix} x_{LC}^P \\ x_{LC}^Q \\ P_G \\ i_d \end{bmatrix} + \begin{bmatrix} 0 \\ \cdots \\ \gamma \end{bmatrix} \tag{36}$$

where $\mathcal{I} = I - [0 \epsilon 00]$. Model (36) is in the standard state space form with extended state variables $x = [x_{LC}^P x_{LC}^Q P_G i_d]$ since $\mathcal{I}$ is structurally invertible.

C. Critical Qualitative Indices

Matrices J_1, J_2, J_3 and J_4 are operating conditions dependent in the described model (36). If they are evaluated around a given nominal operating point once, this model represents a commonly used linearized coupled real power/voltage dynamics model. It is interesting to note that under the general conditions typically used, the DAE model for coupled real power/voltage dynamics is restated in a standard state space form consisting of coupled ODEs in the newly defined state space [20], [21].

J_2 as the main QI for assessing feasibility of an equilibrium: The singularity of the matrix J_2 should be studied since when it occurs, the model must be kept in its DAE form.[14] Observe also that the above derivation has an implied assumption that the matrix J_2 is invertible. The singularity of this matrix is closely related to the nonexistence of power flow solution of a general electric power network interconnection. A nonsingular J_2 effectively says that, specified real and reactive power load demand, one could compute the voltage magnitudes and angles at load buses. Assuming generators to be ideal voltage sources (fixed nodal angle and voltage magnitude), the requirement for J_2 to be invertible is analogous to requiring that this power could be delivered to the loads and that the voltage magnitudes and angles at load buses are uniquely defined. Assume further, that the real power/voltage decoupling assumption holds. Under this assumption requiring that J_2 be invertible implies that for specified real and reactive power load demand P_L and Q_L this power can be supplied from an infinitely large real and reactive power supply (a generalization of maximum power transfer conditions [22]). Similarly, specified reactive power demand, maximum reactive power transfer limit is met [23, Chapter 4]. If any of these are violated, the system is not feasible in the steady-state power transfer sense. It is a conjecture of the first author that some basic power transfer problems that may have occurred during the typical blackouts are closely related to the abnormal conditions quantifiable by analyzing properties of J_2 over the range of loading and system conditions of interest. This is based on the definition of J_2 in (30). It can be seen from this definition that this singularity occurs when for given (P_L, Q_L) demand, there is no solution for load voltages and angles. We will illustrate this on the example of NPCC system below.

Moreover, it follows from the model given in (27) that an equilibrium may cease to exit also when ϵ_1 in (27) becomes singular. It can be seen from (27) that this may occur when a combination of $(J_3 - J_4 J_2^{-1} J_1)$ becomes numerically singular.

We propose these as possible precursors of steady-state (feasibility)-related abnormalities.

[14]The relevance of obtaining standard state space form instead of the DAE form for control purposes is huge. Recall that most of the well-established control design tools assume the former.

Of course, assuming that steady-state precursors are nonsingular, the next question is how stable the system is with respect to small demand deviations $\dot{c}_1$ and $\dot{c}_2$ in (34) and (35) and small deviations in tie-line flows coming from the neighboring areas. A conventional stability analysis for large-scale linear dynamic systems is applicable to these problems [24]. The only problem is computational complexity because of generally very high-order systems, with the related conservative results, and difficulty of analyzing structural disturbances. For this more involved criteria are needed. Given the fundamental difficulties with the analysis, another possible path is to ensure feasible and stable operations through a multilayered control design.

APPENDIX B. BASIC MODELING ASSUMPTIONS DURING NORMAL CONDITIONS

It is straightforward to recognize that modeling the full system dynamics of a power plant, of the prime movers, generators (both electromechanical and electromagnetic characterization), and its local (primary) controllers, quickly leads to a very high-order model for each individual power plants. The order of a coupled dynamic model (24), (25) for an electric power system is the order of each power plant multiplied by the number of plants. In order to obtain more workable models, depending on the phenomena of interest, lower-order models are routinely used by both industry and researchers. These often require assumptions that are not met over the broad ranges of operating conditions, in particular when the system is stressed due to major equipment failures. Classess of models for studying particular subproblems [23, Chapter 6] are derived under some or all of the following assumptions.

- **A steady-state equilibrium for forecast demand in the entire interconnection exists.** This is a very strong assumption that implies sufficient generation and delivery capacity for the interconnection as a whole to have a steady-state solution. In the NPCC example presented later, we illustrate the criticality of this assumption as each control area schedules its own resources for the assumed exchanges with the neighbors. When the power flow exchanges are not as assumed, the basic feasibility of supply meeting demand comes into question. This is the main reason for the need to monitor on-line exchanges between the control areas within the interconnection.[15]
- **The deviations are small during normal conditions** This assumption allows to use linearized models around assumed nominal operating point for designing control to regulate and stabilize system variables in response to hard-to-predict load demand deviations.
- **Real power/voltage decoupling assumption** is often made in both dynamic and equilibria studies. The physical argument underlying separation of frequency and voltage dynamics comes from separating electromechanical from electromagnetic conversion in generators [23]. The steady-state decoupling of real power and reactive power flows in a typical transmission line assumes that the ratio between the line resistance and line reactance is small, voltages are held very close to 1 per unit and the phase angle differences across the transmission lines are small [26].
- **Temporal separation of frequency dynamics** into several time horizons assumes typical singular-perturbation conditions (the faster than modeled dynamics are assumed stable, and the slower ones are assumed constant [27]). Consequently, distinct models are derived to capture very fast frequency deviations driven by fast random load fluctuations assuming voltage unchanged, the somewhat slower minute-by-minute frequency deviations driven by demand variations, and the like.
- **Temporal separation of voltage dynamics** into several time horizons is based on similar notions as the temporal separation of frequency dynamics is. However, reactive power and voltage deviations are often not modeled nor controlled systematically. Exceptions to this are current practices by the Electricite de France and Italy.
- **Localized response to disturbances and monotonicity** At the equilibrium, monotone systems decrease the magnitude of their state response when the magnitude of the disturbance increases [28], [50], [51]. For example, when electric demand increases, voltage decreases. This must be accounted for when designing the controllers. Controllers then need to have gains that decrease the demand in order to bring voltage up.

[15]Industry's concern with this theoretical issue is addressed by the simultaneous feasibility studies of scheduled interchanges using Transmission Load Relief (TLR) methods. As an Electricity Reliability Organization (ERO) is being defined according to the recent US Energy Bill, the same question is likely to re-surface with respect to reserve allocation for reliability and the cost of reliability. Future regional transmission organizations must address the same questions [25].

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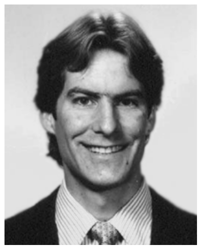

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