PSERC Future Grid Initiative Proceedings

Prepared for PSERC Industry-University Meeting on Preparing for the Future Grid

Power Systems Engineering Research Center

Empowering Minds to Engineer the Future Electric Energy System

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PSERC Future Grid Initiative Proceedings

Papers Authored by Researchers in the DOE Funded Project
"The Future Grid to Enable Sustainable Energy Systems"

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on Preparing for the Future Grid
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Power Systems Engineering Research Center

The Power Systems Engineering Research Center (PSERC) is a multi-university Center conducting research on challenges facing the electric power industry and educating the next generation of power engineers. More information about PSERC can be found at the Center's website: http://www.pserc.org.

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Organization of the Proceedings

This proceedings provides an overview of and papers from on-going work in the PSERC Future Grid Initiative funded by the U.S. Department of Energy for the project “The Future Grid to Enable Sustainable Energy Systems.” The papers were prepared for presentation at the PSERC Industry-University meeting on May 29-31, 2013, at the University of Wisconsin-Madison. The theme of the meeting is “Preparing for the Future Grid.”

The proceedings is divided into three section:

- **Introductory Section:** This section contains tables of contents and an overview of the Initiative prepared by Vijay Vittal, PSERC Director.
- **Part I**: Research papers from the six research thrust areas are provided in order of presentation on May 29.
- **Part II**: Additional papers not for presentation appear in this part. The papers are from authors of broad analysis white papers.

The six thrust areas in the PSERC Future Grid Initiative are:

	Thrust Area	Leader
1	Electric Energy Challenges Of The Future	Gerald Heydt, Arizona State
2	Control and Protection Paradigms of the Future	Chris DeMarco, Univ. of Wisconsin-Madison
3	Renewable Energy Integration – Technological and Market Design Challenges	Shmuel Oren, Univ. of California, Berkeley
4	Workforce Development	Chanan Singh, Texas A&M
5	Computational Challenges and Analysis Under Increasingly Dynamic and Uncertain Electric Power System Conditions	Santiago Grijalva, Georgia Tech
6	Engineering Resilient Cyber-Physical Systems	Tom Overbye, Univ. of Illinois at Urbana-Champaign

The Future Grid Initiative also had white papers on these broad analysis topics:

- The Information Hierarchy for the Future Grid (Peter Sauer, Univ. of Illinois at Urbana/Champaign, Lead)
- Grid Enablers of Sustainable Energy Systems (James McCalley, Iowa State Univ., Lead).

The complete set of white papers are available on the PSERC website. In general, reference documents, presentation slides, posters, and archived webinars for all Future Grid Initiative work can be found on the PSERC website (http://www.pserc.org).

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The Future Grid to Enable Sustainable Energy Systems: An Overview of the Results Accomplished

Vijay Vittal, PSERC Director, *Arizona State University*

I. Introduction

This document provides an overview of the research accomplishments and the white papers generated in the PSERC Future Grid Initiative supported by the DOE. In this Initiative, investigators from PSERC conducted research to facilitate the seamless transformation of today's electric grid to enable the following objectives:

- Plan and operate the grid with increased penetration of renewable resources while meeting designated carbon regulation requirements
- Design grid architecture to support renewable resource penetration and transformation of demand as a resource
- Manage increased dependence on control, communication, and cyber-physical systems to hand grid complexity
- Develop analytical tools to account for increased variability and stochastic nature of generation resources and demand
- Envision and design the appropriate workforce training tools to address the technical objectives.

The PSERC team identified six technical thrust areas and two broad analysis topics to address the technical challenges identified in the Initiative. The technical thrust areas and the broad analysis topics are depicted in Fig.1.

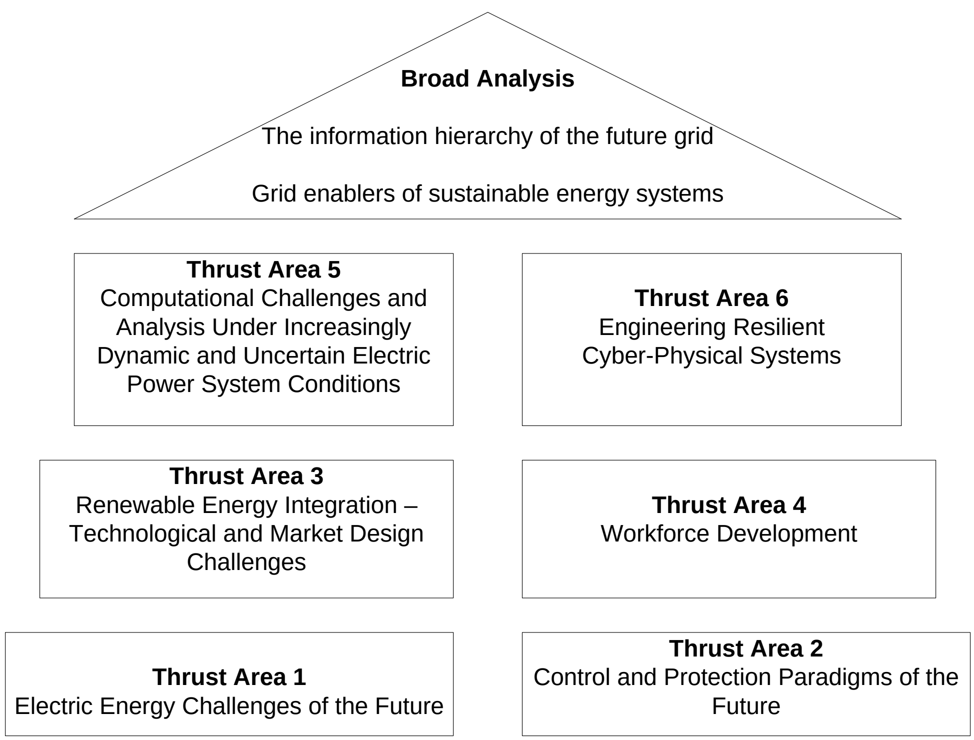

Fig. 1 Technical thrust areas and broad analysis topics

Each technical thrust area had several tasks which addressed the technical challenges listed above. These tasks in turn addressed several cross-cutting themes that provided solutions to the technical challenges. The cross-cutting themes are illustrated in Fig. 2 below.

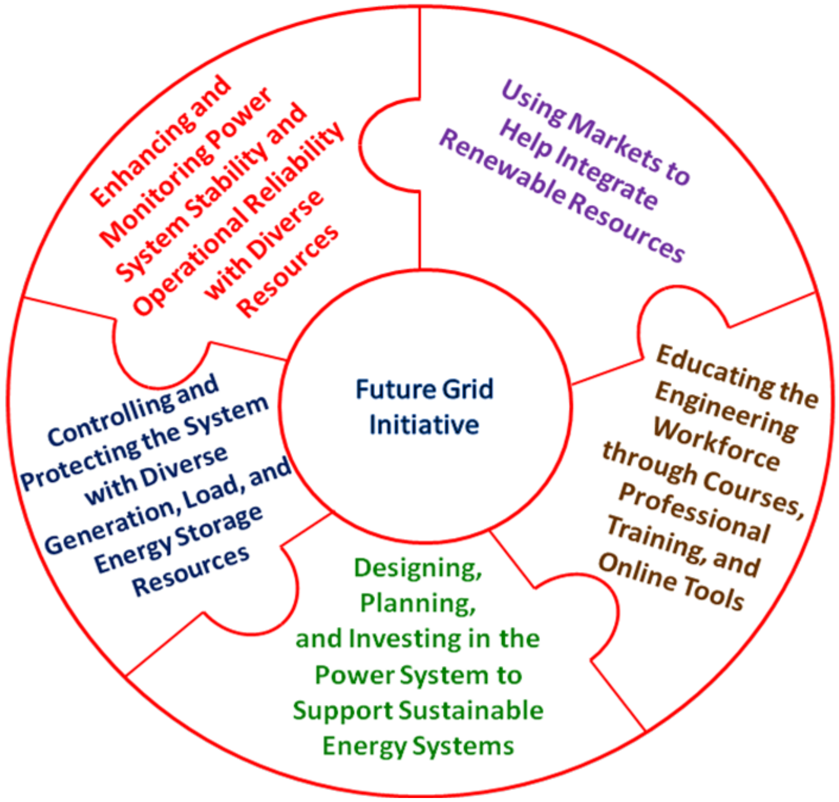

Fig. 2 Cross-cutting themes in the Initiative

These cross-cutting themes tackle technical challenges that need to be overcome to accomplish the objectives of this project. The tasks develop innovative approaches to obtain solutions applicable to large realistic power systems and demonstrate proof of concept on actual test systems. In several tasks new algorithms and analytical tools to handle uncertainty, use of wide-area measurements, and interdependency between cyber-physical systems are developed and demonstrated.

Two other recent reports have addressed issues closely related to the topics addressed in this initiative. They include [1, 2]. In comparison to [1] which was primarily based on the discussions held at a symposium of invited experts, this Initiative involves research conducted by PSERC researchers that was jointly identified by PSERC university researchers and industry members as being critical in envisioning and implementing the grid of the future keeping in mind that a legacy system with a significant capital investment has to seamlessly transition to enable future scenarios. The research conducted in this project also includes development, testing, and implementation of analytical tools and techniques which demonstrate the applicability of the approaches developed to future scenarios rather than a collection of expert opinions as reflected in [1]. The results developed also identify several quantitative and qualitative metrics that are essential in designing and operating the grid of the future taking into consideration increased renewable resource penetration and information from a large set of advanced sensors and measurement devices.

The primary emphasis in [2] was to examine the extent to which renewable energy resources could meet the electricity demands of the continental U.S. in the future. The report postulates that critical attributes of renewable resources, such as geographical diversity and variability and uncertainty in output, pose challenges to power system operation. In contrast, this Initiative specifically develops algorithms and tools that incorporate these attributes and demonstrate the applications of these developments in operating power systems and electricity markets that are an integral component of power system operation in many parts of the U.S.

Another distinguishing feature of the work described in this report in comparison to [1, 2] is the emphasis on workforce training based on the technical issues examined in the project. A host of educational and engineering workforce training modules and tools have been developed. These tools and modules have a variety of delivery modes which include; courses at universities, short courses, textbooks, professional training, and online tools.

A brief description of the tasks in each of the cross-cutting themes is presented below. The research conducted in this Initiative has resulted in key outcomes that address the objectives outlined for each task in the various cross-cutting themes. These outcomes are highlighted below in the description for each task. A detailed description of the outcomes in each of the tasks is provided in the papers that appear later in this proceedings.

II. Cross-Cutting Themes

1. Enhancing and Monitoring Power System Stability and Operational Reliability with Diverse Resources

This cross-cutting theme includes three tasks which tackle technical topics associated with control of wind energy resources and storage for stability enhancement, operational and planning considerations for resiliency, and phasor measurement unit (PMU) based tools for monitoring operational reliability. Each of these tasks is outlined below along with their accomplishments and results generated.

Hierarchical Coordinated Control of Wind Energy Resources and Storage for Electromechanical Stability Enhancement of the Grid (task 2.2)

Christopher DeMarco, Lead, University of Wisconsin – Madison
Collaborators: Bernard Lesieutre and Yehui Han, Univ. of Wisconsin-Madison

The work under this task developed control methodologies and designs that address the problem of maintaining grid electromechanical stability in light of increasing percentage of production from power-electronically coupled renewable resources, such as wind. The challenge in maintaining stable frequency control can arise as synchronous generators, the traditional grid-stabilizing mechanisms, are displaced by wind resources. In this scenario, very modest amounts of battery-based energy storage, which offers small magnitude, high-bandwidth control action, is demonstrated to be a valuable complement to much slower acting active power control available from wind resources. This task developed distributed control architecture and specific design algorithms that coordinate these different classes of control resources across multiple grid locations (wind and storage need not be co-located). The control performance is enhanced by employing dynamic state estimators at each controller, augmenting local information with a small number of remote synchrophasor measurements.

Accomplishments: With the underlying objective of maintaining stable grid frequency regulation and electromechanical response, developed control designs to make best possible use of the new characteristics of power-electronically-coupled wind energy and electrical storage resources. The controllers are complemented with a distributed estimation architecture to inform control actions. Each controller/observer uses local measurements, enhanced by a very modest number of remote synchrophasor measurements when available.

Results: Tools are designed to enable wind generation resources to be more effective contributors to grid frequency control. Control designs could also apply to responsive loads and other new, power-electronically-coupled resources.

Operational and Planning Considerations for Resiliency (task 6.2)

Ian Dobson, Iowa State University

This task quantifies power system resilience so that it can be monitored and maintained. Two approaches to quantify resilience are developed. First, resilience is quantified by processing the standard line outage data that is already gathered by utilities. The average tendency for line outages to propagate is a new metric of resilience that can be estimated from about one year of the data. The average propagation can also be used to compute the chances of large numbers of outages using a validated branching process model. Second, the stress across an area of a power system is quantified by combining synchrophasor measurements at the border buses of the area to obtain an angle across the area. The objective of the proposed new area angle is to quickly monitor stress changes due to line outages within the area with an easily understandable index.

Accomplishments: Developed first practical method to quantify cascading line outage risk from one year of standard utility data. Developed methods to monitor overall stress in a given area from synchrophasor measurements obtained at the border of the specified area.

Results: Software that utilities and regulators could use to process standard data reported to NERC to quantify annual cascading performance of large areas in terms of number of transmission line outages. Subject to further testing, the system stress metric might provide real-time monitoring of severe line outages with an understandable and easily computed combination of synchrophasor measurements. Better situation awareness will facilitate integration of variable generation sources such as wind.

Real-Time PMU-Based Tools for Monitoring Operational Reliability (task 5.4)

Alejandro Dominguez-Garcia, University of Illinois at Urbana-Champaign

Linear sensitivity distribution factors (DFs) are commonly used in power systems analyses, e.g., to determine whether or not the system is N-1 secure. This task proposes a method to compute linear sensitivity distribution factors (DFs) in near real-time without relying on the system power flow model. Instead, the proposed method only uses high-frequency synchronized data collected from phasor measurement units (PMUs) to estimate the injection shift factors (ISFs) through linear least-squares estimation (LSE), after which other DFs can be easily computed. Such a measurement-based approach is desirable since it is adaptive to changes in system operating point and topology. The value of the proposed measurement-based DF estimation approach over the traditional model-based method is illustrated through several examples and a contingency analysis case study for the IEEE14-bus system.

Accomplishments: Estimated linear sensitivity distribution factors (DFs) by exploiting measurements obtained from phasor measurement units (PMUs) in near real-time without the use of a power flow model. The DFs are used by operators in contingency analysis, congestion relief, and remedial action schemes.

Results: A power system monitoring tool that is adaptive to operating point and system network changes using parameters estimated with online measurements. Provides improved situation awareness that can be important in reliably integrating variable generation sources.

2. Controlling and Protecting the System with Diverse Generation, Load, and Energy Storage Resources

Five tasks are included in this cross-cutting theme. These tasks develop specifications and tools to leverage the large national investment in synchrophasor measurement units and address aspects of power system control and protection. The tasks range in diversity from developing a communications architecture for wide-area control to designing control and protection for specific applications to enhance power system reliability and resiliency. The tasks in this cross-cutting theme and their accomplishments and results are outlined below.

Communication Architecture for Wide-Area Control and Protection of the Smart Grid (task 2.1)

Anjan Bose, Washington State University

The rapid increase of phasor measurements on the high voltage power system has opened opportunities for new applications to enhance the operation of the grid. To take advantage of high sampling rate of these measurement data, these applications will require a new information architecture that includes a high band-width, networked communication system connecting computers that can handle geographically distributed data and applications. The specifications for this next generation architecture that will overlay the continental power grids are under intense discussion at this time by organizations such as North-American synchro-phasor initiative (NASPI). In this task a conceptual architecture for such a smart grid and a method to simulate, design and test the adequacy of the architecture for a particular transmission grid is presented. The main difference from typical communication system studies is that the communication requirements from the power grid application requirements are formulated, that is, the design, simulation and testing is from the viewpoint of the anticipated power applications.

Accomplishments: Developed a method to design, simulate and test the IT infrastructure for a given power grid to accommodate phasor measurement data at substations and new smart grid applications, including those applications for wide-area protection and control. Method tested on several power systems, including the Poland Grid (2,383 buses). Simulations showed that in properly designed, high-bandwidth communications networks, expected communications delays (or latencies) can be within a range that supports hierarchically-coordinated control and protection of a smart grid.

Results: Simulations demonstrated that the proposed IT infrastructure and communications network design would meet performance requirements. The simulations also showed the communications bandwidth requirements throughout the network. This methodology could be used to test designs for grids with high penetrations of variable generation.

Improved Power Grid Resiliency through Interactive System Control (task 6.3)

Vijay Vittal, Arizona State University

With the increasing deployment of synchronized phasor measurement units (PMUs), more wide-area measurements will be available and controls based on these measured signals are likely to find broader implementation. To transmit wide-area signals, communication networks are required. However, communication systems are vulnerable to disruptions as a result of which the stability and reliability of power systems could be impaired. This task addresses a critical issue related to engineering resilient cyber-physical systems. It provides two approaches to utilize wide-area measurements in control and also guarantee robustness of the control in the event of loss of communication of the measured wide-area signal. The approaches developed in this work could be used to establish controls resilient to communication failures in power systems. Additionally, this work is particularly important with regard to leveraging the large national investment in installing PMUs.

Accomplishments: Increase grid resiliency using a hierarchical set of wide area synchronized measurements with a fault-tolerant control framework to effectively deploy corrective control with a static VAr compensator (SVC). Controller adjusts to performance issues in the associated underlying communication networks.

Results: A control design that uses new sources of wide area measurements to enhance grid stability while providing control robustness in the event of communications errors. Enhances resiliency of the cyber-physical system with high penetrations of uncertain variable generation and leverages the large national investment in synchrophasor measurement devices.

Wide-Area Control Systems (task 1.4)
Mani Venkatasubramanian, Washington State University

Recent advances in wide-area monitoring, communication and computational technologies have paved the way for development of sophisticated wide-area control systems for the large-scale power system. Advanced control designs are needed for ensuring operational reliability of the future power grid faced with complexity of high percentage of renewable power generation. Novel control designs are proposed in this task for addressing transient stability phenomena in power grids using synchronized wide-area measurements. Model prediction based wide-area transient stability control is designed wherein specific control choices are decided by evaluating the effectiveness of different actions in real-time and by monitoring the closed-loop wide-area system response. Methods for detecting subsynchronous oscillations introduced by incorrect power electronic control settings at wind farms are also discussed briefly.

Accomplishments: Taking advantage of new synchrophasor technologies, developed a new wide-area hierarchical voltage controller, and a new wide-area transient stability controller. The voltage controller addresses reliability concerns due to power electronic interfaces, such as with wind and solar technologies, while providing grid-wide coordination of substation voltage controllers. To stabilize the system after large contingencies, the transient stability controller uses a formulation that predicts the evolution of the system and makes control decisions accordingly.

Results: Algorithms have been tested through simulations. Need to start working with industry on actual designs and implementations. The controllers address stability issues that could pose concerns with high penetrations of uncertain variable generation.

Hierarchical Coordinated Protection of the Smart Grid with High Penetration of Renewable Resources (task 2.3)
Mladen Kezunovic, Texas A&M University

In this task, a new hierarchically coordinated protection (HCP) concept that mitigates and manages the effects of increased grid complexity on the protection of the power system is proposed. The concept is based on predicting protection circumstances in real-time, adapting protection actions to the power system's prevailing conditions, and executing corrective actions when an undesirable outcome of protection operation is verified. Depending on an application, the HCP concept may utilize local and wide area measurements of the power system parameters, as well as non-power system data, such as meteorological, detection of lightning strikes, outage data and geographic information. Since HCP introduces intelligence, flexibility and self-correction in protection operation, it is well suited for the systems with increased penetration of renewables where legacy solutions may be prone to mis-operate. Such instances are unintended distance relay tripping for overloaded lines, insensitive anti-islanding scheme operation, and inability to mitigate cascading events, among other system conditions caused by renewable generation prevailing in future grids.

Accomplishments: Developed the "Hierarchical Coordinated Protection" concept which is based on (1) predicting protection needs in real-time, (2) adapting protection actions to the power system's prevailing conditions, and (3) executing corrective actions when the condition is verified with power system data from intelligent electronic devices (such as PMU's) as well as non-power system data (such as meteorological, lightning strike, and geographic information). Protection under this concept is better suited for integrating renewable generation, avoids unnecessary tripping of overloaded lines, improves anti-islanding controls, and mitigates cascading events, among other system conditions in the future grid.

Results: Testing shows that the new approach, when implemented with the legacy protection system, has superior performance when compared to existing protection approaches alone. The predictive, adaptive, and corrective features of this protection allow the system to be more flexible as output from renewable generation varies.

Resiliency for High-Impact, Low-Frequency (HILF) Events (task 6.1)
Tom Overbye, University of Illinois at Urbana-Champaign

Geomagnetic disturbances (GMDs) have the potential to severely disrupt electric grids worldwide. However, prior to the start of this task power engineers had limited ability to study the impacts of GMDs on their systems. In this task work is conducted in coordination with key stakeholders (NERC, EPRI, government, manufacturers and individual utilities) to develop a methodology for integrating GMD assessment into the power flow and transient stability applications. A methodology for GMD sensitivity analysis is also developed. Results from this work have been integrated into commercial tools and are now available to the electric utility industry.

Accomplishments: Developed a modeling methodology to integrate the calculation of geomagnetic disturbance (GMD) impacts from solar storms into power flow and transient stability applications, allowing for estimations of the likelihood that GMD impacts could result in power system voltage instability.

Results: Matlab code was developed for assessing the sensitivities of the geomagnetically-induced currents on particular transformers to the geomagnetically-induced electric fields on individual transmission lines. This will lead to better assessments of system vulnerability to solar storms. This work provides an example of how new tools can help quantify vulnerabilities to the grid.

3. Designing, Planning, and Investing in the Power System to Support Sustainable Energy Systems

This cross-cutting theme primarily addresses the topic of the future energy delivery infrastructure. It includes four tasks that deal with the planning and design of the transmission and distribution systems with increased penetration of renewable resources.

A National Transmission Overlay (task 1.2)
James McCalley, Iowa State University
Collaborator: Dionysios Aliprantis, Iowa State Univ.

This task presents a five-step design framework of a high-capacity transmission system at the national level. This framework is applied to the U.S. power system to design robust transmission overlays for four future scenarios, including a reference case, high offshore wind, high solar, and high geothermal. Simulations of aggregated U.S. power system models suggest that a national transmission overlay provides benefits via lower operational and investment costs, increased resilience and flexibility, reduced CO2 emissions, and improved dynamic performance.

Accomplishments: Designed a U.S. interregional transmission overlay to facilitate the growth of wind, solar, nuclear, geothermal, and clean-coal generation over the next 40 years. The associated design process and the necessary tools were also developed. The design process co-optimizes generation and transmission, identifying a minimum cost transmission network and corresponding generation expansion plan in terms of location, capacity, and technology. The task also conducted “reachability” analysis of power system dynamics to capture uncertainties in (1) model parameters, (2) operating condition (e.g., load levels, generation dispatch, and voltage levels), and (3) disturbances to the system state (such as equipment/line outages).

Results: Planning analyses quantified the value of the development of a national transmission overlay. Related benefits to the overlay include (a) decreased cost per unit reduction of CO_2; (b) increased resilience to large-scale disturbances; and (c) increased flexibility with lowered cost in adapting to future unfolding scenarios. A national transmission HVAC overlay improves "connectivity" among areas and the dynamic frequency response of areas with high renewable penetration. A high-capacity HVDC overlay improves frequency response and can be used to "transmit variability."

Computational Issues of Optimization for Planning (task 5.2)
Sarah Ryan, Iowa State University

Increased integration of renewable energy and price-responsiveness of demand impose significant uncertainties on long-term resource planning. Fuel price and intermittent generation uncertainties can be incorporated into planning optimization problems as probabilistic scenarios. Market behaviors can be captured in multi-level leader-follower formulations. Both approaches greatly increase computational complexity relative to deterministic, single-level optimization. This research task has included two complementary thrusts: (1) improving a scenario reduction heuristic for centralized expansion planning, and (2) devising a solution procedure for a tri-level model of decentralized expansion planning. The scenario reduction heuristic proposed leads to choosing very similar expansion decisions as does a standard scenario reduction method, but the overall computation time for reducing the scenario set and solving the reduced problem is substantially lower. The hybrid iterative algorithm for the tri-level model finds optimal transmission expansion plans in reasonable computation times when tested on realistic test systems.

Accomplishments: Developed improved computational methods for long-term resource and transmission planning under uncertainty in demand and fuel prices. Customized and tested a method to efficiently reduce the number of scenarios that must be considered, thereby reducing the computation time. Expanded the optimization problem to a tri-level model of transmission and generation expansion in a centrally coordinated wholesale market, thereby capturing both technology choices and market influences. The top level represents a centralized transmission planner. The second level depicts the expansion planning decisions of multiple generation companies. The third level is an equilibrium model of operational decisions by the generation companies and the system operator to meet demands of load-serving entities in a wholesale electricity market.

Results: The lower computational burden of planning under uncertainty will allow more operational details and planning choices in analyses. The tri-level solution algorithm quickly identifies combinations of transmission projects that promise higher net benefits. Better transmission plans will expand the use of renewable resources, equalize locational prices, and prevent undue market influences, resulting in lower prices for consumers and viable profits for producers.

Integrating Transmission and Distribution Engineering Eventualities (task 1.1)
Gerald T. Heydt, Arizona State University

The main topical coverage in this task is transmission engineering. The topics addressed are innovative high voltage DC (HVDC) technologies; and innovative overhead transmission technologies. Key elements of the results relate to multi-terminal HVDC systems, networked HVDC, high temperature low sag (HTLS) overhead transmission, phase compaction, and high phase order. Relating to HVDC, an illustration of expansion of the Pacific DC intertie is described. Relating to HTLS, a summary of the main application areas for upgrading is presented – and these are mainly for thermally limited critical paths. The results of high phase order include the underpinnings of transmission theory for these systems.

Accomplishments: Analyzed advantages and disadvantages of selected innovative transmission technologies such as six-phase AC (and other high phase order), multi-terminal and meshed network HVDC, and high temperature, low sag transmission.

Results: By identifying technological and cost issues associated with alternative transmission conductors and transmission voltages, informed discussions can occur on transmission expansion planning to support renewable generation technologies.

Hierarchical Probabilistic Coordination and Optimization of Distributed Energy Resources and Smart Appliances (task 5.3)

Sakis Meliopoulos, Georgia Institute of Technology

Massive deployment of Distributed Energy Resources (DERs) (wind, solar, PHEVs, smart appliances, storage, etc.) with power electronic interfaces will change the characteristics of the distribution system: (a) Bidirectional flow of power with ancillary services, (b) Presence of non-dispatchable and variable generation, and (c) Non-conventional dynamics → inertia-less characteristics of inverters. To manage this system and harness its potential two major approaches have emerged: (1) Market Approach through incentive/price markets and local controls, and (2) (proposed approach) coordinated approach by the creation of an active distribution system supervised with a distributed optimization tool. This task describes an infrastructure for monitoring and control supervised by a hierarchical stochastic optimization tool that enables: (a) maximization of value of renewables, (b) improved economics by load levelization (peak load reduction) and loss minimization, (c) improved environmental impact by maximizing use of clean energy sources, and (d) improved operational reliability by distributed ancillary services and controls.

Accomplishments: Defined the requirements of an infrastructure that enables optimal use of distributed resources (both utility and customer-owned) through real-time, hierarchical monitoring and control. Created a stochastic optimization algorithm that coordinates the operation of non-dispatchable resources (e.g., renewables) and other resources including storage, smart appliances, and PHEVs. This centralized approach relies on a sophisticated infrastructure of metering, communications, analytics and controls as well as on participation (i.e., consent) of customers.

Results: Based on comprehensive studies of application on utility-scale systems, a business case analysis justifies the investment in the proposed optimization scheme. The analysis includes an economic assessment based on anticipated benefits on system operation, economics and reliability versus the anticipated costs. This integrated approach to power system operations maximizes the value from the use of renewable generation technologies.

4. Using Markets to Help Integrate Renewable Resources

The proposed research under this cross-cutting theme aims at understanding and quantifying the impact that massive integration of renewable resources will have on the power system in terms of efficiency, operational reliability, economic consequences and environmental outcomes. It also focuses on the design and evaluation of technological and market based approaches to mitigation the adverse impact of such integration. Six tasks are included in this cross-cutting theme.

Decision-Making Framework for the Future Grid (task 5.1)

Santiago Grijalva, Georgia Institute of Technology

This task presents a decision-making framework that encompasses all the emerging decision makers across the electricity grid, and two specific decision-making mechanisms. The conceptual framework developed links the various decision making agents to their individual goals, to the various decision points, and to the objectives of the grid at the various spatial and temporal scales. The first mechanism consists of a scheduling algorithm based on mixed-integer linear programming allowing residential users to optimally schedule their energy use in a dynamic pricing environment. Benefits include economic gains for electricity users and performance gains for electricity providers. The second mechanism consists of a method to optimally design electricity price signals so that, when users maximize their individual benefit, they adopt an energy schedule that maximizes at the same time the provider's benefit. Potential benefits include enhancing the economic dispatch, bridging the gap between individual and system objectives, and supporting new business models for electricity providers.

Accomplishments: Developed a scheduling algorithm to allow residential “prosumers” (i.e., cyber-physical entities that can consume, produce, store and/or transport electricity) to optimally schedule their energy use in a dynamic pricing environment, for a given time horizon. Also, developed a method to optimally design electricity price signals for retail markets so that when residential consumers maximize their benefit individually, they adopt an energy schedule that also maximizes the electricity provider's benefit.

Results: In addition to their prescriptive potentials (provide concrete guidance on how decision makers should act), scheduling algorithms also have descriptive potentials (illustrate through simulations why decision makers could be better off if new technology or policy is implemented) and normative potentials (demonstrate how decisions should be made so that these changes are effectively realized). Research could suggest new business models and foster collaboration on future grid research.

Direct and Telemetric Coupling of Renewable Energy Resources with Flexible Loads (task 3.1)
Shmuel Oren, University of California, Berkeley

This task develops a stochastic unit commitment model for assessing the reserve requirements resulting from the large-scale integration of renewable energy sources and deferrable demand in power systems. A scenario selection algorithm inspired by importance sampling for reducing the representation of uncertainty and a Lagrangian relaxation decomposition algorithm for solving the problem is used. Three alternative demand response paradigms are presented for assessing the benefit of demand flexibility in absorbing the uncertainty and variability associated with renewable supply: centralized co-optimization of generation and demand by the system operator, demand bids and coupling renewable resources with deferrable loads. Simulations for a model of the Western Interconnection will be conducted to verify the proposed ideas.

Accomplishments: Developed a short-term two-stage stochastic unit commitment model representing the operation of day-ahead and real-time electricity markets to analyze coupling contracts that coordinate the consumption schedules of deferrable loads with renewable resources.

Results: This work shows the value of contracted renewable resources, supplemented by spot electricity purchased from the grid, to serve such flexible loads. Business models are explored for serving such loads or for aggregating load flexibility to provide wholesale balancing energy and reserves. Using the stochastic unit commitment model, daily cost savings of 2-3% were demonstrated against a time series model of renewable power production calibrated against one year of NREL wind power production data for a reduced system of the California ISO.

Mitigating Renewables Intermittency through Non-Disruptive Distributed Load Control (task 3.2)
Duncan Callaway, University of California, Berkeley

This task explores the coordination of aggregations of thermostatically controlled loads (TCLs; including air conditioners and refrigerators) to manage frequency and energy imbalances in power systems. The task focuses on central control of loads and examines (1) strategies to control loads with limited communications and control infrastructure, (2) the potential to arbitrage variations in wholesale electricity prices by shifting demand over short timescales and (3) develops an understanding of the economic potential for various residential loads to provide power system services.

Accomplishments: Developed new methods to model and control aggregations of thermostatically-controlled loads that reduce communications and power measurement requirements, and minimize temperature deviations for users. Evaluated how different real time communications abilities affect ability to accurately estimate local temperature and ON/OFF state of loads, and controllability of loads. Finally, analyze thermo-statically controlled load resource potential, costs, and revenue potential associated with TCL control in California

Results: Renewables integration requires power system flexibility (e.g., managing frequency response and energy imbalances) that can be provided by demand response. Results lay groundwork for a demonstration.

Planning and Market Design for Using Dispatchable Loads to Meet Renewable Portfolio Standards and Emissions Reduction Targets (task 3.3)

Timothy Mount, Cornell University
Collaborators: K. Max Zhang and Robert J. Thomas, Cornell Univ.

The primary objective of this task is to develop an integrated multi-scale physical and economic framework to determine the system and environmental benefits of Deferrable Demand (DD). In this framework, aggregates of Plug-in Electric Vehicles (PEV) and of thermal storage at different nodes are managed optimally using a stochastic form of Multi-period Security Constrained Optimal Power Flow (MSCOPF). The MSCOPF also includes cost/damage coefficients for emissions at different nodes as well as the fuel and ramping costs for generating units. The research conducted in the task will examine the effectiveness of DD in reducing congestion on the network and cost to customers.

Accomplishments: Developed an integrated multi-scale physical and economic framework for modeling deferrable demand to evaluate the effects of stochastic renewable sources and deferrable demand on total system costs and emissions from generating units.

Results: Initial analyses for a test network in the Northeast demonstrated how deferrable demand can:

- Flatten the daily dispatch pattern of conventional generators,
- Mitigate the variability of wind generation,
- Reduce ramping costs and maintain reliability,
- Lower costs to customers,
- Improve environmental quality (to be completed).

Probabilistic Simulation Methodology for Evaluation of Renewable Resource Intermittency and Variability Impacts in Power System Operations and Planning (task 3.4)

George Gross, University of Illinois at Urbana Champaign
Collaborator: Alejandro Dominguez-Garcia, Univ. of Illinois at Urbana-Champaign

This task develops a comprehensive, stochastic simulation approach for power systems with renewable and storage resources operating in a competitive market environment. The approach explicitly represents the uncertain and time-varying natures of the loads and supply-side resources, as well as the impacts of the transmission constraints on the hourly day-ahead markets. Monte Carlo simulation techniques are adopted to emulate the side-by-side power system and transmission-constrained hourly day-ahead market operations. The approach quantifies the power system economics, emissions and reliability variable effects. The implementation aspects of the methodology so as to ensure computational tractability for large-scale systems over longer periods are also examined. Applications of the approach include planning and investment studies and the formulation and analysis of policy.

Accomplishments: Developed a comprehensive, stochastic simulation approach for power systems with renewable and storage resources operating in a competitive market environment. The approach has explicit representation of (1) uncertainty in conventional, variable energy resources, and loads; (2) time-varying loads and renewable and energy storage resources; and (3) time-dependent transmission usage. The approach is particularly suitable for longer-term studies of power system operations, planning, economics, investment, and policy analysis/formulation.

Results: The following results were obtained through extensive testing using numerous sensitivity cases on a modified IEEE 118-bus system, making use of scaled ISO load and offer data, and historical wind data in the ISO geographic footprint:

- energy storage and wind resources tend to complement each other and the symbiotic effects reduce wholesale costs and improve system reliability;
- emission impacts with energy storage depend on the resource mix characteristics and the location of energy storage; and,
- storage seems to attenuate the "diminishing returns" associated with increased penetration of wind generation.

Robust and Dynamic Reserve Requirements (task 1.3)

Kory Hedman, Arizona State University

Reserve requirements are integral to ensure N-1; however, network congestion threatens reliability by limiting the deliverability of reserves. Uncertainties from load, area interchange, renewable generation, and contingencies make it difficult to predict transfer capabilities and manage congestion. This task aims to develop new innovative methods that better manage uncertainties are necessary to ensure system reliability in an economical fashion. A portfolio of methodologies to determine reserve zones and reserve levels to mitigate congestion in the security-constrained unit commitment (SCUC) problem is developed.

Accomplishments: Developed systematic ways to determine dynamic reserve requirements (zones and levels) with reserve rules for renewable resources and N-1 contingencies to improve reserve location/deliverability. The algorithms account for the specific operational conditions (e.g., transfer capability, congestion, etc.) to determine the appropriate reserve levels and locations to improve reserve deliverability while also improving economic efficiency.

Results: Using IEEE test systems, demonstrated that robust and dynamic reserves will improve reserve deliverability, reduce costs to integrate renewables, and reduce out of market corrections (e.g., 2% cost savings were obtained).

5. Educating the Engineering Workforce through Courses, Professional Training, and Online Tools

This cross-cutting theme builds on the various research efforts pursued in the initiative to address the important topic of training the future workforce for the evolving electric power system. A range of educational and workforce training tools which utilize a diverse set of tools and technologies to deliver the material to engineering students and professional engineers are developed. This theme has six tasks described below.

Comprehensive Education Tools for Reliability Modeling and Evaluation of the Emerging Smart Grid (task 4.1)

Chanan Singh, Texas A&M University

In the emerging environment, reliability of the power grid will be an important and challenging issue. The subject of power system reliability is thus important but a specialized one. The objective of this task is to develop educational material of sufficient depth so that it can be either learnt on one's own or taught by faculty who do not have sufficient expertise in this area.

To achieve this, two courses have been developed. One of these is a semester long course that can be offered at the graduate level in a university either in class or as an online course. The other is a short course that can be offered in about six hours. This course could be either taken on one's own or taught by an instructor as a short course to industry.

The semester long course has been now fully developed and has been offered twice and class tested. The power points of the short course have been almost completed but videos for explaining these power points are being developed. Both courses will be available on the internet by September, 2013.

Accomplishments: Developed educational material for teaching reliability modeling and evaluation of the emerging power grid with high penetration of renewables, and massive deployment of computer and communication technologies. The audience is university-level instructors, graduate students, and industry professionals.

Results: Two courses are being developed: a semester graduate course and a short course than can be offered in about six hours. The graduate course has been offered twice. It has nine main modules with some sub-modules. The materials for the short course are being organized into seven modules with PowerPoint slides enhanced with videos that present the material. The materials should be accessible on-line by late summer 2013.

Critical Infrastructure Security: The Emerging Smart Grid (task 4.6)

Anurag K. Srivastava, Washington State University

Collaborators: Carl Hauser, David Bakken, M.S. Kim, Washington State University

The increasing convergence of power, communications, and information networks is creating a need for new, multi-disciplinary skill sets for power industry employees. Furthermore, an aging and retiring workforce adds to this challenging problem. An educated and trained workforce is the key to realizing the smart grid vision. This task develops a new course as a step towards providing the needed interdisciplinary training. The course is team-taught and jointly developed by power and computer science faculty members and intended for seniors and graduate students from computer science and engineering.

The semester long course has been fully developed and has been offered twice and class tested. The developed course material will be available online in summer 2013.

Accomplishments: Developed a university course with multi-disciplinary content in data communication, distributed computing, control, cyber-security, and power systems. The course provides background on smart grid technologies (e.g., principles, components and operations) and the related infrastructure needed for secure sensing, communication, computation, and control in a power system. The audience for the course and materials is undergraduate and graduate students in engineering and computer science as well as university-level instructors.

Results: This course titled, "Critical Infrastructure Security: The Emerging Smart Grid "was offered in the Spring of 2012 and 2013. It was team taught and offered to online distance engineering students and engineers from industry as well as in the conventional classroom setting. Course materials will be first available in the summer of 2013 with updates occurring as the course is repeated.

Energy Economics and Policy: Courses and Training (task 4.5)

James Bushnell, University of California, Davis

An understanding of the economics of energy markets is necessary for framing reasonable expectations about the likely adoption and usage of any future technologies that will be applied to the nation's electricity grid. In all industries, there are many examples of technologies that have not advanced beyond the University or laboratory research stage. The energy industries feature several economic aspects that further complicate the commercial transformation and adoption of new technologies. This task develops a series of courses designed to develop a richer understanding of the economic issues confronting businesses, regulators, and researchers in the energy industries.

Accomplishments: Developed a Masters, Ph.D. and professional development courses in energy economics and policy. Designed for both non-economists (with backgrounds in energy technology and engineering) and economists interested in applications to energy. Also, for online interactive learning, implemented "The Electricity Strategy Game." The website for this interactive game is at https://esg.haas.berkeley.edu.

Results: Masters-level course aimed at graduate students in economics, engineering, sciences and public policy offered through Haas School of Business at Univ. of California, Berkeley. Research-level (PhD) material offered through Department of Economics at Univ. of California, Davis. Practitioner-level material offered through short courses at ISOs and Univ. of Cal. campuses. Course materials are available upon request by instructors at accredited universities. Access to The Electricity Strategy Game site is available upon request.

Energy Processing for Smart Grids (task 4.4)

James Momoh, Howard University
Collaborator: Peter Bofah, Howard Univ.

An overall need exists to re-energize the interest in power system engineering and also address topics related to the evolving system technology and issues. Educational material is needed for teaching renewable energy, storage facilities, energy processing, measurement techniques, and smart grid technologies/systems. There is a need to develop a university course on smart grid energy processing to equip students for the future workforce. This task develops a university course for undergraduates and first year graduate students in the field of power engineering.

Accomplishments: Developing a university course, with materials, on energy processing for the smart grid. Educational material is needed for teaching renewable energy, storage facility, energy processing, measurement techniques, and smart grid technologies/systems. This university course is for undergraduates and first year graduate students in power engineering.

Results: While the materials for the comprehensive course on Energy Process for the Smart Grid are being developed, a subset of the material is now being used to teach the introductory course "Fundamentals of Energy Systems" for juniors in engineering. Lecture notes will be collated into a book that will be published and available for purchase. An online e-book version will also be available upon request along with the completed course material syllabus.

PSERC Academy: A Virtual Library of Short Videos (task 4.2)

Raja Ayyanar, Arizona State University

This task aims to take advantage of the advances in e-learning technologies to provide workforce training in the area of power engineering, power electronics and sustainable energy systems. An online library of a large number of short videos, with supporting user-interactive material including simulations, animations and quizzes with instant feedback are being developed. The videos and other training material can be used as a complete self-learning e-resource, as a complement to class lectures, or as a reference material for practicing engineers. As part of the Future Grid Initiative, three modules on basic power electronics, photovoltaic power conversion and wind energy are under development and will be made available publicly through a dedicated website.

Accomplishments: Creating an online library of short (i.e., 15-20 minute) videos on various topics of sustainable energy systems, smart grid and power engineering, and on important background topics required to understand these concepts.

Results: The material for PSERC Academy will be primarily put on the website 'PsercAcademy.asu.edu'. Most of the videos will be on YouTube and the PsercAcademy.asu.edu website will provide links to these under different topic areas. The simulation files and animations will be hosted directly on the PsercAcademy.asu.edu website. PsercAcademy.asu.edu went live in April 2013.

Smart Grid Education for Students and Professionals (task 4.3)
Mladen Kezunovic, Texas A&M University
Collaborators: Sakis Meliopoulos, Georgia Institute of Technology; Alex Sprintson, Texas A&M Univ.; Vijay Vittal, Arizona State Univ.; Mani Venkatasubramanian, Washington State Univ.

This task focuses on development of a textbook on synchrophasor technology to be used for teaching university courses and offering continuing education courses for professionals from industry. The book aims at providing an overview of the current synchrophasor technology and its applications. The book begins with the introduction of the synchrophasor devices, such as phasor measurement units (PMUs), PMU-enabled intelligent electronic devices (IEDs) and phasor data concentrators (PDCs). Then the use of the synchrophasor and synchronized sampling in the areas of transient stability assessment, wide-area stability monitoring and fault analysis is discussed.

Accomplishments: Building a comprehensive educational package for educators, students, practicing engineers, managers, legislators, public officials, among others, by writing a text book and preparing a set of supplemental PowerPoint presentations that may be used. The book will be for students and industry professionals. The text will be co-authored by Sakis Meliopoulos, Georgia Institute of Technology; Alex Sprintson, Texas A&M Univ.; Mani Venkatasubramanian, Washington State Univ.; and Vijay Vittal, Arizona State Univ..

Results: It is anticipated that there will be a camera-ready manuscript ready for publishing by December 31, 2013.

III. Broad Analysis Topics

As a part of this initiative, PSERC undertook step to help lead thought about solutions to what can be called "broad analysis" needs. A broad analysis need covers questions that are typically well beyond the scope of typical academic research projects in terms of size and definition. The questions are not strictly engineering, often involving issues of policy as well as stakeholder perspectives and impacts. Broad analysis may also include the exploration of major new ideas to facilitate discussion on their applicability such as on research needs, commercialization potential, and other similar topics. Importantly, they are questions that often need to be answered to reach public interest objectives for the supply, delivery and use of electric energy.

Two broad analysis topics were pursued: 1) The information hierarchy for the future grid and 2) Grid enablers of sustainable energy systems. A series of white papers on each of these topics were developed. The white papers addressed the following key areas:

The Information Hierarchy for the Future Grid

Cyber-Physical Systems Security for the Smart Grid
Manimaran Govindarasu, Iowa State University

This white paper discusses defense against cyber attacks and the need for security of the information, infrastructure and applications.

Communication Needs and Integration Options for AMI in the Smart Grid
Vinod Namboodri, Wichita State University

Communication requirements and design considerations for backhaul and home area networks to facilitate the automated metering infrastructure are the topics addressed in this white paper.

Information and Computation Structures for the Smart Grid
Lang Tong, Cornell University

The need for a foundational understanding of the underlying computation and information hierarchy for the future smart grid are discussed in this white paper.

Networked Information Gathering and Fusion of PMU Measurements
Junshan Zhang, Arizona State University

This white paper addresses the need for networked communications of synchrophasor data and how such architectures need a robust design to avoid cascading communications failures.

Grid Enablers of Sustainable Energy Systems

Primary and Secondary Control for High Penetration Renewables
Christopher DeMarco, University of Wisconsin-Madison

This white paper argues for a new control design philosophy exploiting improved grid measurement and sensor technologies to allow renewable resources to more broadly contribute to grid active power and frequency control.

Toward Standards for Dynamics in Electric Energy Systems
Marija Ilic, Carnegie Mellon University

New paradigms (using improved grid measurement and sensor technologies) for standards for dynamics are addressed in this white paper.

Future Grid – The Environment
Ward Jewell, Wichita State University

This white paper discusses three environmental concerns (mitigating greenhouse gases including transportation, adapting changing climate, and availability of water) and makes observations about the needed steps to address the stated concerns.

Transmission Design at the National Level: Benefits, Risks and Possible Path Forward
James McCalley, Iowa State University

The benefits, risks, and possible future solutions to building a national transmission overlay are identified in this white paper. The white paper also lays out the essential elements to facilitate continued dialog on this topic and frames possible paths by which the objectives can be realized.

Distributed and Centralized Generated Power System – A Comparison Approach
James Momoh, Howard University

The strengths and weaknesses associated with centralized generation and distributed generation resources are identified and discussed in this white paper.

As presented above the white papers produced address a range of topics of which are highly relevant in terms of the critical issues associated with the grid of the future. The topics are discussed in detail and a set of diverse implications and solutions are presented. The white papers developed are publicly available and have been posted on the PSERC website.

IV. Future Research

Based on the research conducted in this initiative and the ideas generated in the white papers a number of future research ideas are identified. These ideas are presented below and organized based on the cross-cutting themes identified above.

Enhancing and Monitoring Power System Stability and Operational Reliability with Diverse Resources

1. Improving control design methods by accurately representing wind power variations and load variations. High sampling rate data of wind power variation or high bandwidth information on spectral content of such disturbances could be used to better approximate real-world disturbances.
2. Extend the new capability to monitor cascading from utility data. Determine the main factors causing cascading from utility data. In particular, determine the main factors contributing to the extended cascades that lead to widespread blackout. Determine metrics to quantify contributing causes of cascading. Extract cascading metrics from heterogeneous data.
3. Accurate estimation of distribution factors in the presence of corrupted measurements or with the availability of only a subset of measurements.

Controlling and Protecting the System with Diverse Generation, Load, and Energy Storage Resources

1. Assessing quality of service (QOS) requirements of synchrophasor data communication for multi-timescale nature of monitoring and control. Design of redundant configuration of intra-utility level communication systems to enhance communication reliability.
2. Examine the impact of data packet error due to communication failures and design controllers resilient to such errors. Extend the concept of redundant wide area control to other applications related to generator control.
3. Develop a control design road-map that introduces few of the wide-area control ideas into existing power systems with a planned transition that allows evolution of the legacy system to future configurations.
4. Explore and assess benefits of the proposed hierarchical coordinate protection applications and examine the important implementation details.
5. Examine the dependence of the geomagnetic disturbances impact on the size of the system model. Examine methods to obtain more accurate system parameters and quantify the associated error if default parameters are used. Identify the set of transformers for which the reactive power losses need to be calculated due to the geomagnetically induced currents. Examine the short term voltage stability aspects due to geomagnetic disturbances.

Designing, Planning, and Investing in the Power System to Support Sustainable Energy Systems

1. Implement a parallel computing platform on a high performance computational platform and enhance Benders' decomposition algorithm to efficiently solve a multi-stage transmission investment optimization under uncertainty, with steady state and dynamic reliability considerations. Enhance the reachability analysis through algorithmic improvements and parallelization.
2. Develop, implement and test methods to reduce the number of scenarios in stochastic programming for rolling time horizon problems. Solve multiple variations of a bi-level optimization problem with uncertainty characterized in the lower-level market equilibrium sub-problem.
3. Investigate feasibility of high voltage DC multiterminal and networked systems. Examine the role of computer relaying in facilitating the implementation of six phase overhead

transmission. Analyze the use of single pole switching in conjunction with high phase order overhead and underground transmission. Examine the impact of phase compaction for overhead transmission engineering.

4. Examine the application of hierarchical probabilistic coordination and optimization of distributed energy resources and smart appliances for providing reserve capacity by determining in real time the amount of load that can be managed. Demonstrate the approach in an actual distribution system.

Using Markets to Help Integrate Renewable Resources

1. Developing a policy paper to describe how the concept of energy prosumer can be used to foster collaborative research to foster a shared understanding among decision makers. Testing the pricing design mechanisms on large-scale cases.
2. Committing or de-committing individual units based on update system forecasts. Developing a multistate formulation of the stochastic unit commitment problem to facilitate revised forecasts and dispatch decisions. Extend the model to an optimal investment model for investment in new generation capacity and include investment decisions on transmission lines. Explore a more detailed model of demand response based on the notion of the "value of storage" akin to the notion of the "value of water" in medium-term hydrothermal planning models, that can be integrated in the stochastic unit commitment model.
3. Investigate the use of networked control systems and model predictive control to minimize excessive thermostatically controlled load switching. Examine refined model and design of controllers that take into account stochasticity. Characterize the shape of ancillary service cost curves and hence the magnitude of thermostatically controlled load revenue reduction.
4. Determine the type of information needed from system operators for customers and aggregators of deferrable demands to provide responses that lower costs and reduce total system costs. Extend the environmental analysis to deal with the detrimental effect of emissions that have a spatio-temporal dependence.
5. Examine in depth the symbiotic interactions between demand response and renewable resources. Examine the impact of increased penetration of renewable resources on the utilization of conventional units. In particular, ramping capability requirements.
6. Refine reserve policies and combine them with stochastic security constrained unit commitment algorithms to obtain robust reserve zones and improve the convergence of the algorithm.

Broad Analysis Topic: The Information Hierarchy for the Future Grid

<u>Cyber-Physical Systems Security for the Smart Grid</u>

- Information and Infrastructure Security
  - Communication: Tailored encryption, authentication and access control mechanisms
  - Device security: Attestation to detect malicious modifications
  - Cyber security evaluation: Security assessment techniques, evaluation of assessment techniques
  - Intrusion Tolerance: Tailored detection, intrusion tolerant architectures
  - Security Management and Awareness: Digital forensics
- Application level security
  - Attach resilience control: Resilient control algorithms, correlation of know system state, anomaly based intrusion detection
  - Attack-resilient wide-area monitoring: Attack resiliency and situational awareness
  - Attach-resilient wide-area protection: Identifying vulnerabilities, cyber-attack templates
- Risk modeling and mitigation
  - Integration of cyber-physical attack/defense modeling with physical system simulation

Communication Needs and Integration Options for AMI in the Smart Grid

- Data volume
  - Data to be collected from consumers
  - Communication architecture to collect data
  - Storage of data
- Customer privacy
  - Metric to quantify customer privacy
  - Optimal information-sharing decisions based on this metric
- Overall requirements
  - Balance data collections needs of utility with customer privacy preservations
  - Optimal design of communication infrastructure to collect, handle, and store data with customer privacy and information security as critical requirements

Information and Computation Structures for the Smart Grid

- Cloud architectures for smart grids
  - Consistency, time criticality, and scalability
  - Reliability, security, and trustworthiness
  - Estimation and control in the cloud
- Information hierarchy in time
  - Real-time scheduling with deadlines
  - Multistate decision and risk-limiting dispatch
- Information hierarchy in space
  - Real time location marginal prices
  - Impact of data inconsistency on real time location marginal prices

Networked Information Gathering and Fusion of PMU Measurements

- Enabling technologies for high availability of synchrophasor measurements
  - Redundancy configuration of intra-utility level measurement systems
  - Deadline-driven data delivery: Quality of service (QoS) requirements of synchrophasor communications, deadline-driven delivery of synchrophasor measurements, queue management, dynamic rate allocation, flow quenching
- Synchrophasor data fusion for post-event analysis
  - Statistical model
  - Decentralized network inference using synchrophasor data
- Middleware communication architecture of synchrophasor data
  - Middleware communications for synchrophasor data
  - Key issues of architecture design for middleware communications: Middleware router deployment, router connection, construction of reliable and resilient overlay network, allocation/management of network resources to meet QoS requirements, scheduling and routing packets with different QoS requirements, regulation of data injection rate to achieve application-specific objectives

Broad Analysis Topic: Grid Enablers of Sustainable Energy Systems

Primary and Secondary Control for High Penetration Renewables

- Design controls schemes to maximally exploit differing control characteristics of the diverse generation and storage technologies
- Exploit modern control design methodologies
- Control and estimation methods needs to facilitate contributions to primary and secondary control from a range of technologies including storage and demand response.

Toward Standards for Dynamics in Electric Energy Systems

- Plug-and-play standards for dynamics, with no requirements for on-line communication
  - Requirement on adaptation of dynamics of each group of components
  - Requirement on interaction variable with neighboring groups of components
  - Determining sufficient conditions
- System-level standards based on minimal coordination of decentralized component-level standards
  - Requirement on the dynamics of each group of components
  - Requirement with regard to participation in minimal coordination of interaction variables managed at the higher system layer
- Interactive protocols for ensuring technical performance according to choice and at value
  - Requirements on exchanging information
  - Requirements on contribution to coordinated control

Future Grid – The Environment

- Green house gas mitigation
  - Create and verify effectiveness of regulations and market mechanisms to reduce CO_2 emissions while meeting environmental goals, economic needs, and reliability
- Adapting to climate change
  - Forecasts of each potential climate change effect
  - Understand ability of existing infrastructure to meet energy needs during extreme temperatures
  - Understand ability of existing infrastructure to withstand more frequent and severe weather events
  - Incorporate findings into planning models to develop appropriate adaptation measure
  - Examine financing and rate adjustments to allow for changes to be made to the system
- Availability of water
  - Determine regional availability of water to the electric energy industry
  - Technologies to reduce water use when needed

Transmission Design at the National Level: Benefits, Risks and Possible Path Forward

- Market driven investment
  - Incentives for inter-regional projects
  - Rate basis for funding investment in transmission
  - Special incentives and structures for building HVDC
  - Concentration of market participants
  - Cooperative agreements between participants
- Federal driven investment
  - Basis for indentifying projects for investment
  - Prioritizing the allocation process
  - Goal oriented infrastructure investment
  - Monetizing reliability benefits
  - Overcoming problems with siting
- Coordinated regional partnerships
  - Process to standardize definitions and benefit calculations of reliability-based investments
  - Mechanism for distributing cost of inter-regional projects
  - Standards and policies for planning and cost recovery of investments
  - Development of regional or super-regional renewable energy initiatives

<u>Distributed and Centralized Generated Power System – A Comparison Approach</u>

- Economies of scale
  - Measurement
  - Capital cost
  - Service cost
  - Maintenance enhancement
  - Land use cost
- Resilience metric
  - Measurement
  - Reliability
  - Stability
  - Protection
- Sustainability metric
  - Measurement
  - Quality of service
  - Emissions
  - Environmental impact
  - Power Quality
- Tools for handling uncertainty
  - Variability issues
  - Co-optimization of resources
- Standards
  - Regulations
  - Land use

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Part I

PSERC Future Grid Initiative Proceedings

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Hierarchical Coordinated Control of Wind Energy Resources and Storage for Electromechanical Stability Enhancement of the Grid (2.2)

Christopher L. DeMarco, Bernard C. Lesieutre, and Yehui Han, *University of Wisconsin-Madison*
Chaitanya Baone, *GE Global Research*

Abstract—**The work under this Task developed control methodologies and designs that address the problem of maintaining grid electromechanical stability in light of increasing percentage of production from power-electronically coupled renewable resources, such as wind. The challenge in maintaining stable frequency control can arise as synchronous generators, the traditional grid-stabilizing mechanisms, are displaced by wind resources. In this scenario, very modest amounts of battery-based energy storage, which offers small magnitude, high-bandwidth control action, is demonstrated to be a valuable complement to much slower acting active power control available from wind resources. This Task developed a distributed control architecture and specific design algorithms that coordinate these different classes of control resources across multiple grid locations (wind and storage need not be co-located). The control performance is enhanced by employing dynamic state estimators at each controller, augmenting local information with a small number of remote synchrophasor measurements.**

I. Introduction

Thrust 2 of the Future Grid Initiative stated its goal in the project's original statement of work: to "define the overall concept for hierarchical coordinated control and protection of the smart grid." Task 2 of the Thrust, reported on here, may be seen as focusing to also serve the key objective of the Future Grid Initiative; that is, to enable higher penetrations of renewable generation and other future technologies into the grid, while enhancing grid stability and reliability.

Many challenges to present-day control and protection practice in the U.S. power grid stem in part from growing penetration of distributed and renewable generation. The most obvious and widely discussed of these is the greater volatility in power injections and operating conditions that can result from significant penetration of power production that follows instantaneous weather conditions. This issue may be seen as part of the motivation for the work of this Task. It has contributed to growing recognition that renewable resources such as wind and solar may need to at least partially regulate their active power output, even if such regulation comes as a trade-off against perfect maximization of available energy production.

As a related issue, the growth of distributed generation and storage, of which renewables are one element, suggests a future grid with less clear boundaries between roles at bulk transmission level versus distribution level. One may anticipate generation, storage, and responsive loads contributing across a wider range of levels in the grid, including the distribution level, with a vastly larger number of participants impacting grid protection and control. Hence, the distributed control architecture developed in this Task sought to accommodate both larger numbers of contributing controllers, and more diversity in their response characteristics (e.g., control bandwidth, saturation limits of available power/energy/ramp rate). The primary focus of this Task targeted control designs for wind generation and battery storage to allow these to better contribute to stable grid electromechanical response. However, it is the authors' hope that the control design and dynamic state observer architecture developed will have broader impact, to allow higher penetration for a wide range of resources that share features of being highly distributed, widely diverse in their response characteristics, and non-synchronous, power-electronically coupled to the grid.

II. Approach/Methods

As noted in the introduction above, large-scale centralized synchronous generators have long been the primary actors in exercising active power and frequency control, and much of the existing grid control framework is predicated upon their dynamic terminal characteristics. Important among these characteristics is the tight "synchronous" coupling between electrical frequency and mechanical rotational speed that is inherent to their design, as well as their substantial rotating inertia. These two characteristics play key roles in determining the electromechanical stability of the electric power grid, and maintaining the grid frequency within an acceptable band. In contrast, modern wind generator systems are typically induction machines, partially or fully connected to the grid

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through power electronic interfaces, and hence wind generators do not present the same level of inertial coupling. The absence of inertial frequency response from modern wind generator systems is a topic of growing concern in power engineering practice, as the penetration of wind generation grows [6], [7]. Prior solutions proposed in the literature and implemented by some wind turbine vendors have sought to address this problem by mimicking the inherent inertial response characteristics of traditional synchronous generators via control loops added to wind generators [8]-[10].

Recent literature has raised concerns regarding limitations this "inertia-emulating" approach [11]. The original statement of work in this Task was motivated in part by a desire to overcome the shortcomings of active power control systems for wind turbines that seek to make the wind machines mimic synchronous generator behavior. Instead, this Task sought to optimally design for the characteristics of the equipment exercising the control (e.g., wind and battery storage), rather than forcing these new technologies to mimic the properties of established technologies. The specific focus was industry standard models of pitch power control in type-3 wind turbines [12], characterizing control response bandwidth and saturation limits (commanded change in power as input, achieved change in active electrical power as output). Similarly, this Task also used models for high power lithium-ion batteries with power electronic interfaces [13], characterizing response from commanded power as input, to grid-interface delivered power as output.

Starting from this general motivation, this Task developed a new approach to power system frequency regulation, with features suited to grid-scale batteries and wind turbine blade pitch control. The dynamic characteristics of these new technologies was treated hand-in-hand with traditional synchronous machine governor control, to develop a comprehensive multi-input control design approach to yield stable electromechanical response and good frequency regulation. We believe this approach is relatively novel in power systems context, in that it respects saturation and bandwidth limitations for a variety of very disparate actuators, all contributing to a common system-wide control objective. To make the method practically feasible for use with multiple controllers that may be widely separated geographically, an observer-based distributed control design utilizing synchro-phasor measurement unit signals ("PMUs") along with local measurements was developed. In addition to the primary, system-wide objective of frequency regulation, this approach allowed the control design to also address other local objectives relevant to the individual pieces of equipment, such as reducing wind turbine drivetrain stress. Key to the distributed dynamic state observers' development under this Task was an effective algorithm to characterize the modal degrees of controllability and observability, with respect to particular electromechanical modes of interest in the grid. In practical terms, this identified the most effective sensor and actuator locations, and allows graceful degradation to less ambitious control objectives when loss of a remote measurement makes a mode of interest no longer observable.

The designs here consider the problem of frequency control to regulate changes in grid frequency due to disturbances such as wind power variation and load variation on a time-scale of milliseconds to tens of seconds. The control actuators (i.e., the hardware implementing variations in active power injection) are classified on the basis of two key capabilities: the speed at which they can provide/absorb regulation power (bandwidth), and the magnitude of power they can provide/absorb (saturation limits). As a first step in the applications here, actuators are classified into two broad classes that are complementary in their bandwidth and saturation limits. These are: (i) low bandwidth, "slow" actuators with broad saturation limits (e.g., power control available by varying blade pitch in wind generators, turbine governor controls in traditional synchronous generators) and (ii) high bandwidth, "faster" actuators with narrow saturation limits (e.g., power control available from battery or ultra-capacitor energy storage).

To perform the control design, we exploited recent advances in Linear-Quadratic (LQ) Optimal Control methods[1] for linear systems subject to input amplitude saturation [14], with added features to accommodate the actuators' bandwidth characteristics. This Task's work augmented this type of state feedback based design (that assume ***all*** system states are available from measurements), to instead allow the controllers to use a distributed, observer-based implementation. As a result, the controllers designed depend only on local measurement signals and a small subset of available remote measurement signals.

To formulate a model appropriate for LQ optimal control design in the power systems context, one begins from a linearized dynamic model for the electromechanical response of the network of interest. In standard textbook presentations [15] this is "state space normal form;" that is, coupled, first-order, linear ordinary differential equations written in a matrix-vector form. Such models are widely used in small-disturbance stability studies in grid applications, and data necessary to populate such a model is a commonly available output of commercial power system analysis software packages. Alternately, such models may be built up from first principles with more basic network and machine data, and implemented in a general purpose control analysis software environment such as MATLAB. For the greatest flexibility in building battery models that are not yet widely available in power system analysis software, this latter approach was adopted for this project.

The model constructed includes both the representation of the grid's electromechanical behavior, and a model of the external "disturbance" of interest, against which the control design is seeking to regulate. For our application and time frame of interest, the disturbance is variation in mechanical shaft power of a wind turbine, as results from wind speed changes on our time scale of milliseconds to 10's of seconds. This representation of the wind disturbance as an "exosystem"

[1] While different in its specific objectives, readers are encouraged to consult a PhD thesis at another PSERC institution, that also makes a strong argument for Linear Quadratic Optimal Control methods to address emerging grid challenges in high renewable penetration scenarios [16].

within the linear state space model is novel in grid applications, but fits well with the framework of [14]. With this exosystem included, the state space formulation is given as:

$$\dot{x} = Ax + B\sigma(u) + E_w w \tag{1a}$$

$$\dot{w} = Sw \tag{1b}$$

$$y = Cx \tag{1c}$$

Equation (1a) describes the plant with state $x \in \mathrm{R}^n$, and σ saturating control input $u \in \mathrm{R}^m$, subject to the effect of an exogenous disturbance represented by $E_w w$, where $w \in \mathrm{R}^s$ is the state of an exosystem. Equation (1b) describes the state space realization of the autonomous exosystem. The output is $y \in \mathrm{R}^p$, and σ is a normalized vector-valued saturation function defined as

$$\bar{\sigma}(s) = \begin{cases} s & if\ |s| \le 1 \\ -1 & if\ s < -1 \\ 1 & if\ s > 1 \end{cases}$$

with

$$\sigma(s) = \left[\bar{\sigma}(s_1), \bar{\sigma}(s_2), \ldots \bar{\sigma}(s_m)\right]^T .$$

The state x would typically includes deviations of power flow variables from the operating point about which one is regulating, along with generator frequency deviations, and any internal state variables of the generators, turbines, and their control systems. Here these states are augmented to include states of any battery energy storage units and their controllers. We wish to control the system from inputs, u; these represent the *commanded* power for that device. For example, in considering a traditional turbine/synchronous generator set, the physical input of turbine value position may be interpreted as corresponding to a certain mechanical shaft power that one wishes to "command" the turbine to produce.

Any physical control system producing power ultimately has limits on the power output that may be achieved. The key point in the context here is that these limits may be quite narrow for some devices, and *may be routinely encountered even in normal action of control around an operating point.* Wind turbine blade pitch control offers an intuitive example of the importance of reflecting these limits. One expects that blade pitch may be varied only over a narrow range of a few degrees, before the pitching mechanism reaches hard mechanical limits on its operation. The consequence is that we want to explicitly account for these limits in our control design, or we may achieve poor regulation as control action saturates, and fails to provide any further incremental benefit.

Also important to our application here is the treatment of the disturbance "exosystem;" as noted above, the model seeks to capture the impact of changes in wind turbine mechanical power through the disturbance state, w. For readers aware of the vast literature and significant challenges in representing wind speed variation, it may appear optimistic to attempt to capture wind-induced power variation through a simple unforced, linear differential equation such as (1b). However, recognize that our needs in representing disturbances fast time scale regulation of frequency (milliseconds to tens of seconds) are quite limited. Hence it is sufficient to capture the frequency content (spectrum) and magnitude of typical wind power variations, and the structure of (1b) is adequate. One simply creates an exosystem that is completely undamped (i.e., S has all pure imaginary eigenvalues), with frequencies matching the dominant frequencies observed in measure wind power variation spectra. This gives a very compact, analytically tractable means of reflecting in the model the expected magnitude and spectra of wind variations, against which the controller must regulate.

With the small signal model of the power system and its controllers established, along with the disturbance exosystem model, the goal of regulation can be summarized quite simply: one seeks to maintain a weighted sum of squares of the state variables x within a certain bound. The key observation of the authors of [14] was that with LQR design methods could be extended to yield designs that simultaneously regulate x, while maintaining the input u generated by the controller to within saturation limits, all while experiences disturbances w. For readers not familiar with the typical mathematical methods of linear state space design (as reflected in such texts as [15]), the problem is reduced to computation of a feedback matrix, denoted F. The operation of a controller designed in this fashion is simply to generate control commands as a linear function of state; that is, $u = Fx$. In particular, for the LQ based design, for the F selected, and with Fx is substituted for u in (1a), yields solutions for x(t) and u(t) in (1) that minimize the functional:

$$J = \int_0^\infty \left(x^T Q x + u^T u\right) dt ,$$

i.e., the selected control minimizes an integral of a quadratic function of state plus a square of the control (the control "effort").

However, for application in power systems, the state vector x can easily number in the hundreds to thousands, and represent quantities spread over hundreds of square miles. For each local controller to depend on all these quantities is clearly impossible. The classic result of the "separation principle" in linear control theory [15] comes to the rescue: roughly speaking, if one optimally *estimates* the states, and then uses this estimate in place of the actual state vector, the asymptotic performance of the controller is not degraded. However, in the power system application, the dimension of x so large that the use of an estimator remains problematic. Fundamentally, one wants to "restrict the attention" of a given local controller to the system's behavior only over a small number of degrees of freedom.

The insight required to produce manageable designs for local dynamic state observers rests on grid characteristics long recognized in small disturbance stability studies. Of the many natural modes of oscillation that may occur in the electromechanical dynamics of a large power network, the vast majority are extremely well damped. These naturally decay to zero very rapidly, *without any additional action of controllers*. Moreover, a single generator (or storage unit) exercising active power modulation at a given bus in the network is often able to exercise effective control only over a subset of those troublesome modes. The consequence of these insights is that if one wishes to build a local state observer to "feed" a controller at that bus, reconstruction of state can be limited to recovering behavior on a low dimensional subspace.

Observe the very practical interpretation of building distributed, linear observer/controllers that each regulate on low dimensional subspaces. A local observer/controller pair that observes and regulates k oscillatory modes will be a linear transfer function of order $2k$. For example, if one seeks to regulate just one oscillatory mode with a given controller, the transfer function is simply a second order linear filter, and hence *extremely* easy to implement in practice.

The philosophy of controls developed in this project confronts the challenge of the nonlinearities in the design/optimization process, but restricts the allowable controllers to standard, linear transfer functions. This potentially sacrifices some performance, relative to that which might have been achieved with more complex, nonlinear controllers. However, it has the strong advantages of making the controllers easier to implement, and more importantly, easing the job of verifying correct controller performance. In a complex system such as the power grid, the authors believe this latter point is critical, and is sometimes not adequately addressed. Designs that ensure verifiability of controller performance (as chosen here), may be preferable to designs that provide higher performance when operating properly, but whose correct operation is harder to verify.

III. RESULTS

The wide variety of test cases and control/estimation scenarios examined in the course of this project far exceed the presentation limits in this short summary document. Interested readers are highly recommended to consult project publications [1]-[4], as well as the PhD thesis [5]. However, as a sampling of the control performance achieved, we select a test case examined in conference paper [3]: a modified version of the standard IEEE 14 bus example system. In this simulation test, we replaced the traditional synchronous generators that appear at buses 6 and 8 of the sample network with wind generators, represented using the standard Type-3 wind machine model of [12]. Synchronous generators remain at buses 2 and 3. A controllable battery is added as supplemental high-bandwidth power source only at the bus 2 location. Note that while the battery will help regulate against disturbances in wind power output, originating at buses 6 and 8, the battery is connected remote from those buses. Bus number 1 is treated as the slack/swing bus. The remaining buses have standard P-Q and impedance loads connected. In this particular test case, the battery is the only supplemental control added; both the traditional generators and wind machine retain their standard, unmodified control schemes.

To monitor a single signal representative of system frequency, a weighted average of the frequencies at each of the traditional generators is employed. The resulting frequency variation due to the wind power variations for the base case, with no supplemental control, is shown in Figure 1. Recall that the wind variations are modeled as a persistent, periodic disturbance produced by the exosystem of (1b). As a result, the frequency variations show a persistent, periodic error; they are essentially the wind power time behavior "filtered" through the natural electromechanical response of the power system. The addition of the supplemental battery control yields frequency behavior displayed in Figure 2. It should be evident that the control action provides a significant improvement in regulation towards zero frequency error (note the very different vertical scales between the two figures).

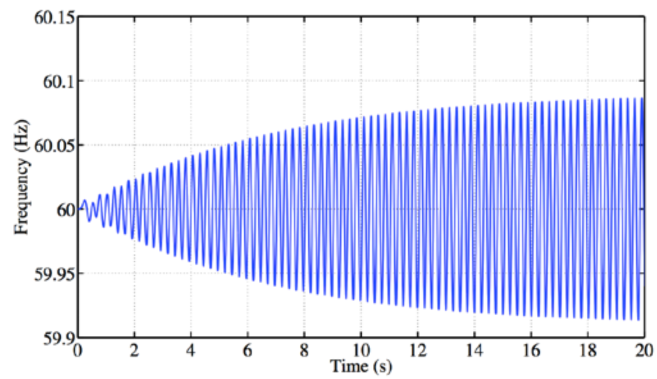

Fig. 1. Freq. Variation: no Supplemental Control

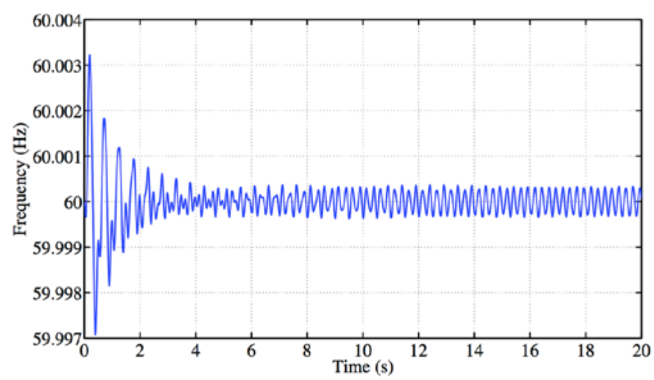

Fig. 2. Freq. Variation: with Supplemental Control

In this test case, the supplemental control was designed to also help address a secondary objective, that of reducing wind machine drivetrain stress. To model stress, the wind turbine/generator sets are represented as multiple coupled rotating masses, and stress is monitored via incremental shaft torsional flex. For the base case (no supplemental control), torsional stress is displayed in Figure 3 (same simulation case as Figure 1). The case with supplemental control (same simulation case as Figure 2) is displayed in Figure 4. Because torque stress reduction is a secondary objective, improvement is less dramatic than that for frequency regulation; however, stress approximately halved by the control action (again, note the relative vertical scales in the two figures).

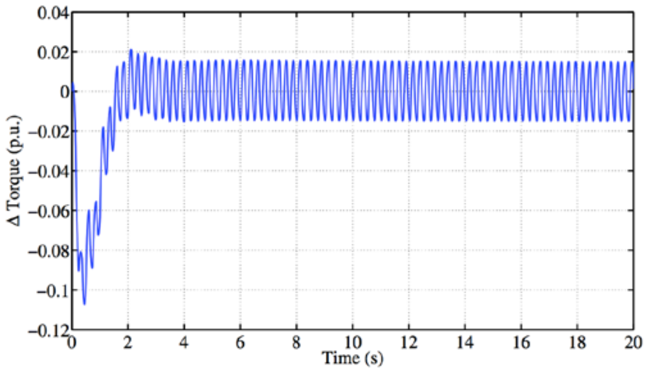

Fig. 3. Stress (Δshaft-torque): no Supplemental Control

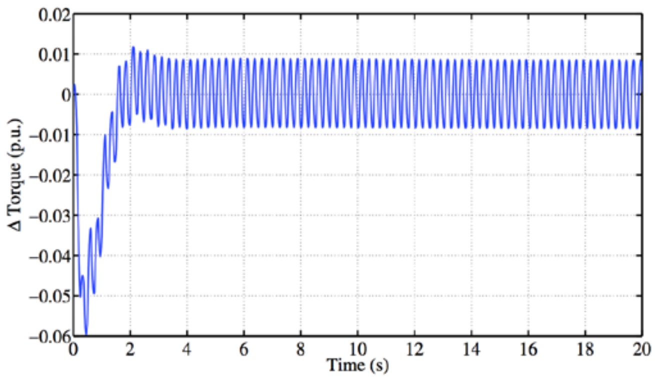

Fig. 4. Stress (Δshaft-torque): with Supplemental Control

A final important feature of this test case is verification that the design did in fact respect the saturation limits on available control action. In this case, these limits are predominantly the maximum power that may be absorbed/delivered from the battery. The hypothetical example here was intended to approximate characteristics of experimental test installations of grid scale lithium-ion batteries. A maximum power limit of ±2 MW was assumed, translating to 0.02 pu on the 100 MVA base of this small example system. A plot of the battery's power injection in the case with supplemental control is illustrated in Figure 5. Note that the magnitude of the control action remains well below the 0.02 pu saturation limit.

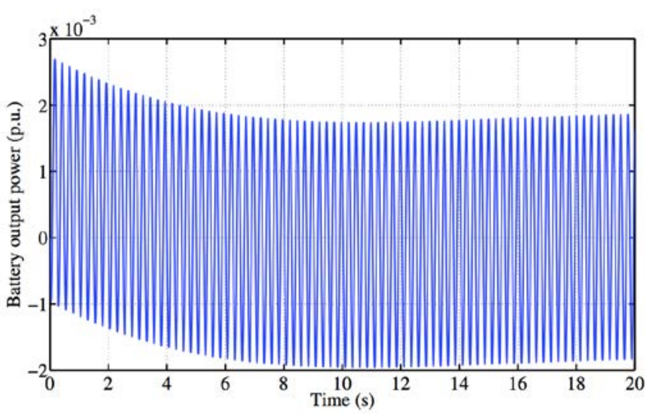

Fig. 5. Battery Output Power w/ Supplemental Control

IV. Conclusions

The main contributions of this project may be summarized as follows:

- A new approach to power system frequency regulation with control contributions from multiple distributed elements with diverse characteristics. The approach takes into account the saturation and bandwidth limitations of the actuators, through a modal-focused control design approach. The test cases examined in the project were tailored to new actuator technologies relevant in future grid active power/frequency control: wind turbine blade pitch control, and high-power lithium-ion battery storage. However, the general control design architecture is broadly applicable to a range of new grid technologies.
- A distributed, observer-based control design approach to make the proposed method practically feasible for geographically distributed power systems. The emerging PMU technology is utilized to make the distributed, dynamic state observer-based design feasible for large-scale power systems.
- A Hautus matrix-based algorithm is developed to efficiently compute the degrees of controllability and observability for a subspace of power system electromechanical modes of interest. A mathematical relation between the amount of energy required to control/observe a given mode and the associated Hautus matrix is derived. This approach identifies the most appropriate measurement signals and actuator bus locations to be employed in the control design.
- Along with the system-wide objective of enhancing the grid electromechanical stability while regulating frequency, additional issues relevant to wind turbine control designs were also addressed within this general control architecture. In particular, it was demonstrated that the control objective could be augmented to also consider wind turbine drivetrain stress during disturbances. Control designs were demonstrated in simulation to reduce drivetrain stress simultaneous with contributing to stable system-wide frequency regulation.

Viewed broadly, the control architecture developed in this project is important to facilitating higher penetration of renewable resources, as it allows resources with very diverse characteristics to contribute to the key goal of maintaining stable electromechanical response of the grid. The test cases of wind turbines and lithium-ion battery storage were examined in detail in the project. However, the general premise of optimally exploiting characteristics of new technologies, rather than forcing them to mimic traditional synchronous machine response, holds promise for allowing greater control contributions from other resources such as photovoltaics and responsive loads.

V. Future Work

The control design methods developed in this project were examining thoroughly in the context of well-validated simulation models. With simulation results in industry standard models established, testing in physical hardware would constitute the most substantial next step for future work. Other possible enhancements to the design methods include the following:

- The wind power variations and load variations considered in this work were idealized representations. High sampling rate data of wind power variations or high bandwidth information on spectral content of such disturbances could be used to better approximate real-world disturbances.
- The proposed control philosophy could be implemented in other applications that require coordination of multiple, diverse elements with different saturation limits and bandwidth, in reactive power support for voltage control, or in coordination of batteries and ultra-capacitors.
- Because the proposed design method relies on the communication of PMU signals across geographically distributed locations, the effect of propagation delays associated with communicating PMU signals on the control performance should also be incorporated. Complementary work on this topic of control signal delay was completed under Task 6.3 of the Future Grid Initiative.

VI. Access to products

The project publications listed below describe individual algorithms developed. A complete description of algorithms and test case results may be found in Dr. Baone's PhD thesis, available through the UW Digital Collections system, at: http://digital.library.wisc.edu/1711.dl/OU4RUUT56LTVX8H

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VIII. Biographies

Christopher L. DeMarco (M'85) received the B.S. degree from the Massachusetts Institute of Technology, Cambridge, and the Ph.D. degree from the University of California, Berkeley, both in electrical engineering and computer sciences, in 1980 and 1985, respectively. He joined the faculty at the University of Wisconsin-Madison, Madison, in 1985. At the University of Wisconsin-Madison, he has served as Electrical and Computer Engineering Department Chair, and currently serves as Grainger Professor of Power Engineering and Site Director for the Power Systems Engineering Research Center (PSERC).

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Operational and Planning Considerations for Resiliency (6.2)

Ian Dobson, Atena Darvishi, *Iowa State University*

***Abstract*—9It is useful to quantify power system resilience so that it can be monitored and maintained, and we develop two ways to do this. First, we quantify resilience by processing the standard line outage data that is already gathered by utilities. The average tendency for line outages to propagate is new metric of resilience that can be estimated from about one year of the data. The average propagation can also be used to compute the chances of large numbers of outages using a validated branching process model. Second, we quantify the stress across an area of a power system by combining synchrophasor measurements at the border buses of the area to obtain an angle across the area. The objective of the new area angle is to quickly monitor stress changes due to line outages within the area with an easily understandable index.**

I. Introduction

In order to engineer a resilient power transmission system we need to develop ways to quantify resilience. While a general idea of resilience can be of some value and contribute to discussion, engineering resilience for power systems operations and planning will be most effective and useful when it is based on quantities that can be monitored or calculated.

In this project, we worked on two new ways to quantify resilience:

A. Quantifying resilience to cascading outages from one year of standard utility data
B. Monitoring line outages by combining synchrophasor measurements at the border of an area

A. Quantifying Cascading from Standard Utility Data

Cascading is the process by which some initial transmission line outages propagate to lead to further line outages, sometimes causing a blackout. Every utility in the USA reports TADS (Transmission Availability Data System) data of forced transmission line outages to NERC. We can process one year of this data from a large utility to estimate the average line outage propagation and hence predict the cascading risk from assumed initial outages.

The average propagation of line outages is a measure of system resilience. In a resilient power system, the propagation is low, initial outages may propagate to cause only a few further outages, the sequence of outages is likely to be short, and the consequences beyond the initial outages are likely to be limited. In a power system that is not resilient, the propagation is higher, it is more likely that the outages will propagate to cause many other outages, and there is a significant risk of a long series of outages leading to a medium or large blackout. Note that the average propagation is a function of the system and an aspect of the system resilience. In contrast, the initial outages are determined by individual component reliability and external factors such as bad weather.

This paper was prepared with the support of the U.S. Department of Energy for The Future Grid to Enable Sustainable Energy Systems, an initiative of the Power Systems Engineering Research Center. I. Dobson and A. Darvishi are with ECpE dept., Iowa State University, Ames IA 50011. For enquiries please contact Ian Dobson, dobson@iastate.edu.

B. Monitoring Line Outages by Combining Synchrophasor Measurements

We published circuit theory that shows how to combine synchrophasor measurements at the border of an area of the power system to obtain an angle across the area [3]. The new area angle indicates the area stress and obeys circuit laws. For example, wheeling 10% more power through the area increases the angle by 10%, and line outages inside the area can increase the overall area impedance and cause the area angle to increase.

We are learning how to apply the area angle to get a real-time bulk indicator detecting some severe line outages in the area directly from the combined synchrophasor measurements. The area angle appears to have better properties for monitoring line outages than pair-wise synchrophasor angle differences or power flows into the area. The overall objective is to be able to get actionable information about the area from the synchrophasor measurements at the border of the area. The real-time monitoring with area angles would complement slower methods based on state estimation, and potentially could allow tracking of severe cascading events involving many line outages. Given the synchrophasor measurements at the buses at all the tie lines to the area and a DC load flow model of the area, the calculations to obtain the area angles from the synchrophasor measurements are straightforward.

II. Approach to Quantifying Cascading

To quantify cascading from standard utility TADS data we perform the following steps:

1) Process the automatic outages in the TADS data by grouping them into the separate cascades, and then into generations of outages within each cascade. This is done in a simple way according to the timing of the outages.
2) Estimate from the data the average propagation of the cascades from each generation to to the next generation. These average propagations are a metric of system resilience. About one year of TADS data from a large utility gives sufficient data.
3) If desired, use a branching process model to estimate the probability distribution of the total number of outages after cascading. The answer also depends on the initial outages, and one can assume either a fixed number of initial outages, or a distribution of initial outages. This process is indicated in Fig. 1. The branching

process calculation uses computer algebra to evaluate the formulas, which are elegant and complicated.

The resilience to cascading is quantified by both the average propagation, and by the probability distribution of the total number of outages after cascading. In contrast, note that empirically determining the chance of large numbers of line outages from observed data takes over a decade, and is not practical for monitoring the resilience. Using the branching process model is quicker and enables practical results using about one year of utility data, because estimating the propagations which are the parameters of the branching model is much more efficient than directly estimating the chance of large numbers of line outages.

The branching process model has been validated for the calculations on several utility data sets. This also confirms that the propagation metric of resilience is meaningful.

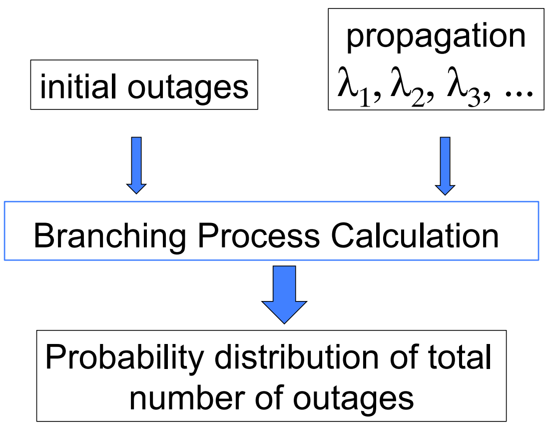

Fig. 1. A branching process model can compute extent of cascading as a distribution of total number of line outages.

III. Results of Quantifying Cascading

We give an example of processing line outages from a publicly available source of TADS data. In order to gain confidence that the results and methods apply more generally than this single data set, we have successfully applied and verified the method on three other data sets from other organizations and the results are similar.

In the data set there are about 860 automatic line outages in a year. Using a simple approach based on the timing of the outages, we group outages into about 500 cascades and then into generations within each cascade. This gives, for example, 625 outages in generation 0, 114 outages in generation 1, 43 outages in generation 2, and so on. We think of the outages in a generation as parent outages, and the outages in the next generation as their children. Then the propagation is the average number of children per parent. For example, the average number of children in generation 1 per parent in generation 0 is $\lambda_1 = 114/625 = 0.18$. Generation 1 has 114 outages and these outages, as parents, produce 43 child outages in generation 2. Therefore $\lambda_2 = 43/114 = 0.38$. Continuing these calculations leads to Fig. 2. In Fig. 2, as the cascade progresses, the propagation λ_k increases from 0.18 and then, although the results for higher generations become noisy due to sparse data for the higher generations, the propagation levels off at an average value of about 0.75.

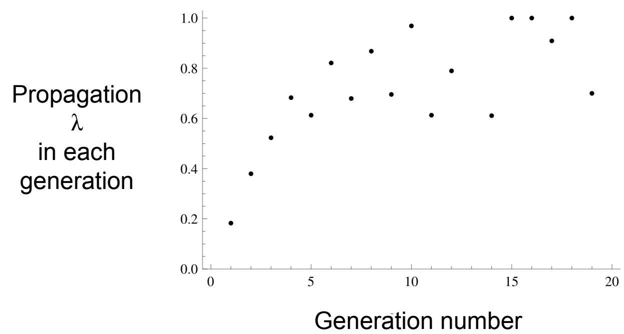

Fig. 2. The increasing propagation λ from utility TADS data

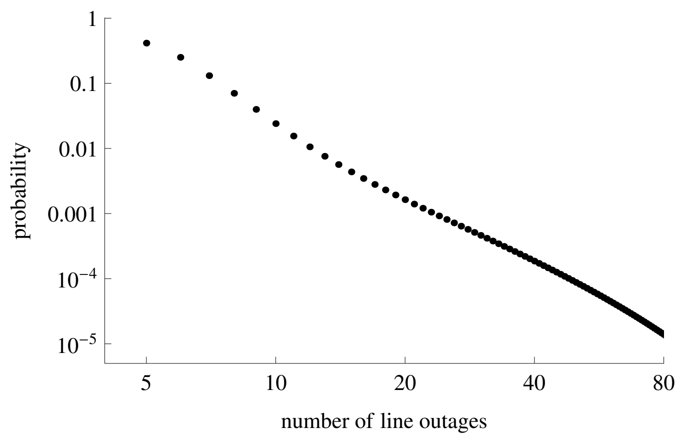

Fig. 3. Predicting cascading failure extent based on utility TADS data

The results for predicting the cascading failure extent in terms of the probability distribution of the total number of outages after cascading is shown in Fig. 3. This calculation assumes 5 initial outages. For example, the probability of more than 20 line outages can be estimated as 0.014 by summing probabilities from the probability distribution in Fig. 3.

IV. Approach to Area Angles

The concept of the voltage angle across a power system area is new and is described in detail in [3]. Here we give a brief overview of the voltage angle across an area.

In a DC load flow of an area of a power system, the voltage phasor angle across an area can be defined by suitably combining voltage angles at buses on the border of the area. For example, to get the angle difference north-south across an area, a weighted combination of angles at buses on the southern tie lines are subtracted from a weighted combination of angles at buses on the northern tie lines.[1]

The angle across an area is a generalization of the angle difference at two buses. The angle across an area is useful because it summarizes the circuit behavior of the area. In particular, the angle across the area satisfies the basic circuit law similar to Ohm's law so that the effective power flow through the area is the product of the angle across the area and the effective susceptance of the area.

The angle across an area seems promising for power system monitoring, and here we are most interested in their application to quantify stress across an area. The stress interpretation of the area angle works in the same way that the angle across a single transmission line indicates the transmission line stress. It is hypothesized that the limits on area angles may usefully capture in a bulk measure some of the salient limits within the area. Here we are interested in how area angles can monitor line outages and the proximity to thermal limits of lines inside the area.

A. Simple Example of Measuring Stress with an Angle.

The motivation for using area angles to measure stress can be illustrated with the simple example of a double line joining bus a to bus b shown in Fig. 4.

We assume lossless lines and a DC load flow and can compare two stress indices, the real power P_{ab} flowing from a to b and the angle θ_{ab} between bus a and bus b. The DC load flow equation from Ohm's law is $P_{ab} = b_{ab}\theta_{ab}$, where b_{ab} is the total susceptance of the lines between a and b.

Under normal conditions, P_{ab} and θ_{ab} are proportional and both indices indicate the stress on the lines. But the indices behave very differently if one of the lines outages as illustrated in Fig. 4. The power flow P_{ab} from bus a to bus b is unchanged, but the admittance b_{ab} is halved and the angle θ_{ab} doubles. Thus the angle θ_{ab} reacts to and indicates the increase in stress caused by the outage, whereas the power flow P_{ab} does not change and does not indicate the increase in stress.

We can also consider the limits on the indices that are determined by the thermal limits (or other flow limits) of the lines. The line outage causes the maximum power flow $P_{ab}^{\max}$ to halve, but the maximum angle $\theta_{ab}^{\max}$ remains the same when the line outages.

In summary, the θ_{ab} index of stress is better than the power flow P_{ab} index of stress because it responds to a line outage, but its maximum value remains constant. One objective of the area angle is to try to get approximately similar benefits for a bulk measurement across an entire area.

B. Detecting Line Outages

As well as detecting stress due to line outages with area angles, we also adapted methods of locating line outages to work within a specific area [1]. In particular, we detected the location of line outages inside a specific area of the power system from synchrophasor measurements at the border of the area and inside the area. We processed the area synchrophasor measurements using a DC load flow model of the area. The processed measurements do not respond to line trips or power redispatches outside the area. The method extends previous methods that locate line trips in an entire network so that they work in a particular area and also deals with cases of islanding. The method will be particularly useful when utilities or ISOs in large interconnections restrict their attention to network models and phasor measurements for only their own area.

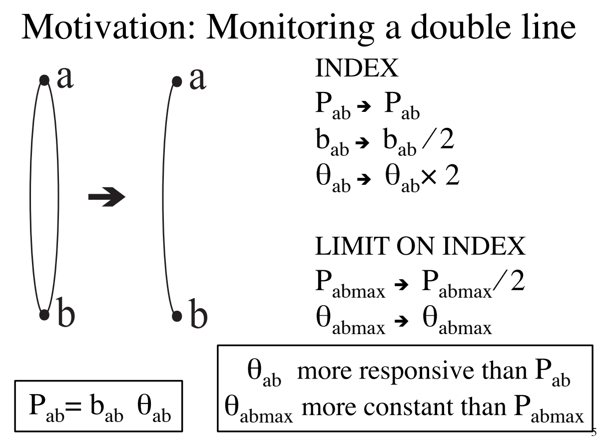

Fig. 4. Comparing P_{ab} and θ_{ab} for monitoring stress in an outage of a simple double line example.

V. Area angle results

We illustrate the use of area angles to monitor line outages with the area of WECC shown with red transmission lines in Fig. 5. The northern border is between the USA and Canada, and the southern border is between Oregon and California and its continuation eastwards. The objective is to measure the north-south stress on the area with the north-south angle across the area and see how it depends on line outages within the area. The north and south border buses at which the bus angles are measured with synchrophasors are shown in Fig. 5. The area angle θ is the following weighted combination of the border bus angles

$$\begin{aligned}\theta = {} & 0.79\,\theta_{\text{CUSTER}} + 0.21\,\theta_{\text{BOUNDARY}} \\ & - 0.42\,\theta_{\text{CAPTJACK}} - 0.46\,\theta_{\text{MALIN}} - 0.02\,\theta_{\text{VALMY}} - 0.05\,\theta_{\text{BENLOMD}} \\ & - 0.04\,\theta_{\text{DAVEJOHN}} - 0.01\,\theta_{\text{WESTHILL}}\end{aligned}$$

These weights are chosen so that the area angle satisfies circuit laws and are calculated from a DC load flow model of the area.

To see how the area angle monitors single line outages in the area, we take out each line in turn and recalculate the area angle. For each of these line outages we also calculate the maximum power that can be passed through the area north to south until one of the lines reaches its thermal limit and the corresponding maximum value of area angle. The results for each line outage, sorted in terms of increasing maximum

[1]Note that when defining the angle across the area, it is required to include all ties lines all the way around the border of the area (otherwise power flows can "escape" without being tracked), so the tie lines must all be grouped into one of the two "sides" of the area.

power through the area (decreasing severity) are shown in Fig. 6. Since these are all non-islanding line outages, and there is not much flow on parallel paths around the area, the power flow into the area remains approximately constant as each of the line outages occurs. That is, the power flow into the area does not indicate the increased stress due to line outages. In contrast, the area angle increases for many of the severe line outages. Also, for some cases the maximum angle limit remains approximately constant despite the outage. These positive results tracking severe line outages suggest that the angle monitoring could be a useful complement to monitoring the power flow into the area. The monitoring of the severe outages by the area angle is imperfect, but this is to be expected when trying to monitor over 700 lines and their limits with one scalar angle as a single bulk area index.

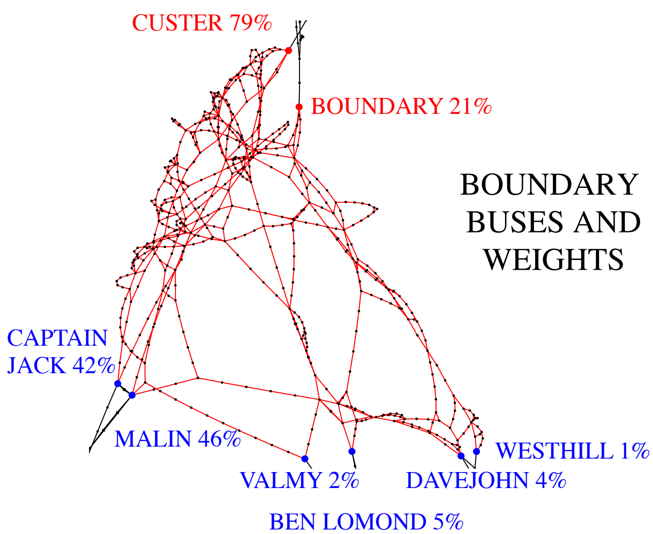

Fig. 5. Area of WECC in red showing boundary buses. The north boundary buses are CUSTER and BOUNDARY with weights 79% and 21% respectively. The 6 southern boundary buses and their weights are also shown.

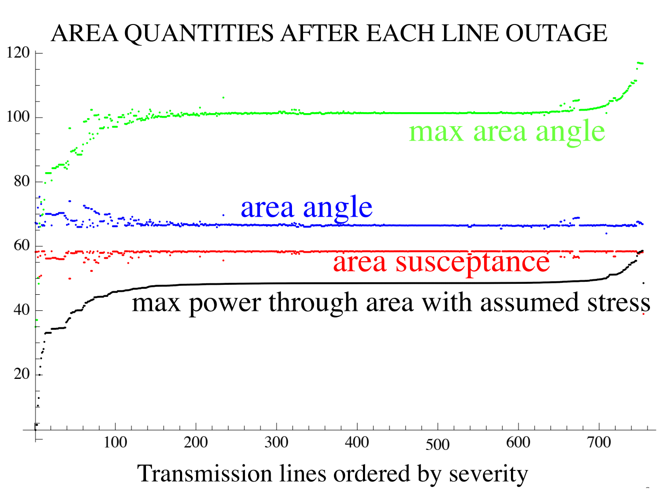

Fig. 6. How area angle and other quantities respond to line outages in the WECC area

VI. Conclusion

A. Quantifying Cascading from Standard Utility Data

We have established the first practical method to quantify and monitor annual cascading risk from standard utility data. The method yields simple metrics of cascading that are the average amount of propagation of line outages as the cascades develop, and estimates of the chances of large numbers of line outages due to cascading. The method and metrics and the modeling of cascades with branching processes have been validated on several industry data sets. The method is in its initial simplest form and we expect that it can be elaborated to be more effective in the future.

The impact on industry and government is that the annual tendency to cascade can be monitored and quantified from utility data that is already collected and reported to reliability organizations. Moreover, the impact of cascading in causing further outages beyond some initial outages can be estimated. For example, if 5 initial line outages are assumed, then the chance of more than 20 line outages can be estimated.

A key property of the method is its efficiency and practicality with one year of data from a large utility; alternative approaches are not practical. For example, the direct approach of empirically determining the chance of large numbers of line outages from observed data takes over a decade. Also, even state-of-the art simulations of cascading neglect many of the dozens of mechanisms by which cascading occurs and in almost all cases remain to be validated against observed data.

The benefits are that quantification of annual cascading performance from standard utility data could allow a direct monitoring of cascading risk and help guide mitigation of cascading risk. The industry can better manage and mitigate a risk that can be quantified. The public would benefit if the method helped to provide a better balancing between cost of the electric grid and large blackout risk. The method also deepens the understanding of cascading failure with the concept of average propagation of outages that is quite easy to understand and measure.

We are very grateful indeed to the organizations that shared the TADS cascading outage data needed to discover and initially establish the new method. In a more general context, the detailed TADS data tends to be confidential, but its format is known. Since it may not be feasible to get widespread access to the data, one way forward is to start to distribute the processing software in prototype form so that the new method can be evaluated for use by the industry and feedback for improvements obtained. That is, if there are barriers moving the data to the processing software, then move the processing software to the data owners. The objective of the remaining 9 months of the project is to write a first version of some prototype software, and make it available to industry.

B. Monitoring of Area Angle with Synchrophasors

A new approach to combining synchrophasor angle measurements can give a real-time bulk monitoring of area stress that is easier to interpret. The area angle is easy to compute from synchrophasor measurements at the border buses of the area and it satisfies circuit laws. We have initially explored how the area angle can monitor stress caused by single line outages inside the area. It has the potential to provide real-time monitoring of severe line outages. It could add value to the investments in synchrophasors by extracting additional actionable information from the measurements. Real-time bulk measurements of angles across areas to monitor severe line outages could help operators quickly detect problems and take actions if the area angles exceeded thresholds. Some blackouts could potentially be avoided.

VII. Future work

A. Future Work for Quantifying Cascading from Utility Data

The research possibilities that leverage the new capability to quantify cascading from utility data are wide open. Five promising directions are:

- Work with industry and regulators to explore and extend the new capability to monitor cascading from utility data. The data processing should be refined and the form of the metrics of resilience and how they are presented and explained should be refined.
- Determine the main factors causing cascading from utility data. (Note that this is different than the well studied mitigation of the initiating component outages). In particular, determine the main factors contributing to the long cascades that lead to widespread blackouts, especially since these causes may be different than for small blackouts, and it is known that some mitigation methods for small blackouts can increase the risk of large blackouts. The nature of causation is much more subtle and complicated for cascading failures (as opposed to component failures) because there are many dependencies between outages in the cascade. The first part of this work would define a sensible metric to quantify contributing causes for cascading, and the second part would apply that metric to determine the main causes of cascading.
- Now that we have the capability to quantity cascading risk from real or simulated cascading data, use simulations to study how various cascade mitigation strategies perform in terms of their effect on cascading risk, and especially their impact on large blackouts.
- The current method counts transmission line outages as a measure of blackout extent. Use simulated cascades to extend the method to other measures of cascading, such as load shed and voltage violations. Then apply the method to the variety of information in observed data. The challenge is to extract useful cascading metrics from heterogeneous data.
- Extend the cascade risk monitoring from cascades within the power system infrastructure to cascades between interdependent infrastructures.

B. Future Work for Area Angle

The research gaps for the area angle are extensive since the area angle is a new concept and there are several different applications in which to work out how to use it. Some promising directions are:

- Optimize the choice of the area to improve the monitoring and consider multiple angles across the area derived from the same synchrophasor measurements.
- The area angles show promise in being able to set alarm thresholds to discriminate severe events and determine whether they are inside or outside of the monitored area. Research is needed on how to set the thresholds and the actions to take when the alarm is triggered.
- Consider the performance of area angles in monitoring severe multiple outages (fast alarm of the potential of serious cascading). This would extend the current project work on single outages to multiple outages.
- Apply the area angles for fast monitoring of developing problems due to voltage collapse and dynamic stability problems. Note that voltage collapse requires an AC power flow formulation, and this is available from the theory in [3].

VIII. Access to products

We are developing prototype software to estimate annual cascading risk in terms of number of lines outages from standard utility data. The intention is to share the software with industry so that they can process their own data and give feedback to guide further development. The software will be made available on a website.

Given the synchrophasor measurements at the border of the area, the formulas for the calculation of the angle across the area are fairly straightforward and are published in [3]. The main challenge is not so much the implementation of the calculation, which should be fairly easy, it is how to make choices of the area and how to best use the angle once it is calculated.

IX. Acknowledgments

We gratefully thank Bonneville Power Administration for making publicly available the outage data that made the cascade monitoring work possible. The analysis and any conclusions are strictly those of the author and not of Bonneville Power Administration. We gratefully thank Reliability First and the Canadian Electric Association for generously sharing outage data. We gratefully thank WECC for access to load flow data.

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X. Biographies

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Real-Time PMU-Based Tools for Monitoring Operational Reliability (5.4)

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***Abstract*—Linear sensitivity distribution factors (DFs) are commonly used in power systems analyses, e.g., to determine whether or not the system is N-1 secure. This paper proposes a method to compute linear sensitivity distribution factors (DFs) in near real-time without relying on the system power flow model. Instead, the proposed method only uses high-frequency synchronized data collected from phasor measurement units (PMUs) to estimate the injection shift factors (ISFs) through linear least-squares estimation (LSE), after which other DFs can be easily computed. Such a measurement-based approach is desirable since it is adaptive to changes in system operating point and topology. We illustrate the value of the proposed measurement-based DF estimation approach over the traditional model-based method through several examples and a contingency analysis case study for the IEEE 14-bus system.**

I. Introduction

In order to monitor operational reliability, power system operators rely heavily on online studies conducted on a model of the system obtained offline [1]. One such study is N-1 contingency analysis, with which operators determine whether or not the system will meet operational reliability requirements in case of outage in any one particular facility (e.g., a generator or transmission line) [2]. In general, these model-based online studies may include repeated computations of power flow solutions using the full nonlinear system model, a linearized model, or, in the simplest case, linear sensitivity distribution factors (DFs) such as injection shift factors (ISFs), power transfer distribution factors (PTDFs), line outage distribution factors (LODFs), and outage transfer distribution factors (OTDFs). For example, in the context of N-1 contingency analysis, ISFs and LODFs are used, in conjunction with an estimate of the system's current operating point, to predict the change in operating point in the event that an outage in certain generating facilities or transmission lines occurs. These post-contingency operating point predictions are then used to determine whether or not the system is N-1 secure. In this paper, we propose a method to compute power system DFs, in conjunction with phasor measurement unit (PMU) measurements of active power bus injections and line flows in real-time, through LSE without relying on a model of the system.

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The conventional model-based studies are not ideal because (i) an accurate model containing up-to-date network topology is required, and (ii) the results from such model-based studies may not be applicable if the actual system evolution does not match any predicted operating points due to unforeseen circumstances such as equipment failure, faults in external areas, or unpredictable levels of renewable generation. For example, in the San Diego blackout, operators could not detect that certain lines were overloaded or close to being overloaded because the network model was not up-to-date, which caused state estimator results to be inaccurate [1]. Thus, traditional model-based techniques may no longer satisfy the needs of monitoring and protection tasks and therefore it is important to develop power system monitoring tools that are adaptive to changes in operating point and topology and to estimate parameters using online measurements. Fortunately, with the installation of PMUs throughout the power system, we are in a position to identify and monitor grid stress in near real-time.

Unlike current system measurements, PMUs measure voltages, currents, and frequency at a very high speed (usually 30 measurements per second) [3], and phasors measured at different locations by different devices are time-synchronized [4]. In this paper, we propose a method to estimate linear sensitivity DFs that exploits measurements obtained from PMUs in near real-time without relying on the system power flow model. These online DFs can be used in numerous applications, including contingency analysis, post-contingency generation re-dispatch, congestion management, and model validation. In particular, we rely on real power bus injection and line flow data obtained from PMUs to compute the linear sensitivity DFs through linear least-squares estimation (LSE).

Linear sensitivity factors are widely known and used in power systems analyses [5], [6]. Existing approaches to computing DFs typically employ so-called DC approximations, which can provide fast DC contingency screening [7]. They do not, however, have the flexibility of adapting to changes in network topology or generation and load variations, which can all affect the actual linear sensitivities significantly. Recent attention has been given to the computation of the line outage distribution factor due to their prominent role in revealing and ameliorating cascading outages [8], [9]. Additionally, work has been done in the area of detecting line outages using PMU measurements [10], [11]. Such proposed approaches still largely rely on a model of the system and utilizes the so-called DC approximation. In [12], phasor measurements were used in online contingency analysis by monitoring buses that had been classified as high-risk by an offline study.

Other applications for PMU measurements include monitoring, protection, and control of power networks (see e.g., [13] and references therein).

With regard to LSE, minimization of the least-squares error in estimation has long been utilized in many diverse fields, including power system state estimation [5]. A significant improvement to the standard LSE is the recursive least-squares (RLS) estimation scheme, in which the estimate is recursively updated as new measurement data becomes available, so as to reduce the computational burden of large matrix operations (see [14], [15], [16] and references therein for variants).

The remainder of this paper is organized as follows. Section II outlines the problem formulation and describes the approach we take to estimate DFs. In Section III, we utilize DFs estimated in real-time in a contingency analysis case study for the IEEE 14-bus test system. We offer concluding remarks in Section IV and directions for further work in Section V. Finally, Section VI explains how to access the products that resulted from this research.

II. Approach/Methods

Distribution factors are linearized sensitivities used online in contingency analysis and remedial action schemes. A key distribution factor is the injection shift factor (ISF), which quantifies the redistribution of power through each transmission line following a change in generation or load on a particular bus. In essence, the ISF captures the sensitivity of the flow through a line with respect to changes in generation or load. Other DFs include the PTDF, LODF, and the OTDF [7], which can all be derived from the ISF. In this section, we describe the proposed approach to estimate ISFs using several variants of LSE and then the computation of other DFs once the ISF estimates have been obtained.

A. Computation of ISFs

The ISF of line k-l (assume positive real power flow from bus k to l) with respect to bus i, denoted by $\Psi^i_{k\text{-}l}$, is a linear approximation of the sensitivity of the active power flow in line k-l with respect to the active power injection at node i with the slack bus defined and all other quantities constant. Denote the active power injection at bus i and time t as $P_i(t)$. Suppose $P_i(t)$ varies by a small amount $\Delta P_i(t)$ and denote the change in active power flow in line k-l resulting from $\Delta P_i(t)$ by $\Delta P^i_{k\text{-}l}(t)$. Then, based on the definition of ISF,

$$\Psi^i_{k\text{-}l} := \frac{\partial P_{k\text{-}l}}{\partial P_i} \approx \frac{\Delta P^i_{k\text{-}l}(t)}{\Delta P_i(t)}, \tag{1}$$

where $\Delta P_i(t) = P_i(t+\Delta t) - P_i(t)$ is the difference between two PMU measurements of the active power injection at bus i at times $t+\Delta t$ and t and Δt represents the time between two consecutive measurements. In order to obtain $\Psi^i_{k\text{-}l}$, we also need $\Delta P^i_{k\text{-}l}(t)$, the quantities for which are not readily available from PMUs. We assume that the net variation in active power through line k-l, denoted by $\Delta P_{k\text{-}l}(t)$, however, is available from PMU measurements. We express this net variation as

$$\Delta P_{k\text{-}l}(t) = \Delta P^1_{k\text{-}l}(t) + \cdots + \Delta P^n_{k\text{-}l}(t), \tag{2}$$

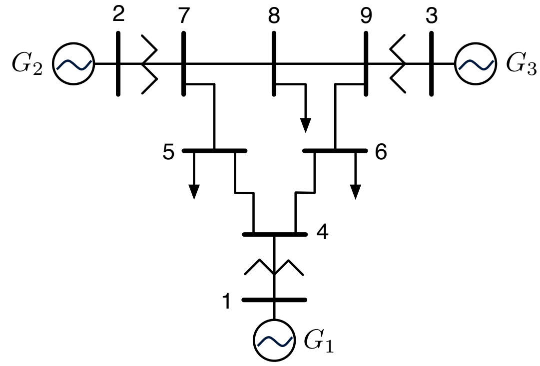


Fig. 1: Network topology for WECC 3-machine 9-bus system.

the sum of active power variations in line k-l due to active power injection variations at each bus i. Equivalently, by substituting (1) into (2), (2) can be rewritten as

$$\Delta P_{k\text{-}l}(t) \approx \Delta P_1(t)\Psi^1_{k\text{-}l} + \cdots + \Delta P_n(t)\Psi^n_{k\text{-}l},$$

where $\Psi^i_{k\text{-}l} \approx \frac{\Delta P^i_{k\text{-}l}}{\Delta P_i}$, $i = 1,\ldots,n$. Suppose $m+1$ sets of synchronized measurements are available. Then, with $t = j\Delta t$, let $\Delta P_{k\text{-}l} = [\Delta P_{k\text{-}l}[1],\ldots,\Delta P_{k\text{-}l}[j],\ldots,\Delta P_{k\text{-}l}[m]]^T$, $\Delta P_i = [\Delta P_i[1],\ldots,\Delta P_i[j],\ldots,\Delta P_i[m]]^T$, and $\Psi_{k\text{-}l} = [\Psi^1_{k\text{-}l},\ldots,\Psi^i_{k\text{-}l},\ldots,\Psi^n_{k\text{-}l}]^T$. Further, suppose $m > n$, then we obtain the following overdetermined system:

$$\Delta P_{k\text{-}l} = \begin{bmatrix}\Delta P_1 & \cdots & \Delta P_i & \cdots & \Delta P_n\end{bmatrix}\Psi_{k\text{-}l}. \tag{3}$$

For ease of notation, let ΔP represent the $m \times n$ matrix $[\Delta P_1,\ldots,\Delta P_i,\ldots,\Delta P_n]$. Then, the system in (3) is of the form $\Delta P_{k\text{-}l} = \Delta P \Psi_{k\text{-}l}$. Next, we discuss three measurement-based methods to obtain an estimate of $\Psi_{k\text{-}l}$.

1) Least-Squares Estimation: The vector of ISFs for line k-l, $\Psi_{k\text{-}l} = [\Psi^1_{k\text{-}l},\ldots,\Psi^n_{k\text{-}l}]^T$, can be obtained by solving the following LSE problem:

$$\min_{\Psi_{k\text{-}l}} \; e^T e, \tag{4}$$

where $e = \Delta P_{k\text{-}l} - \Delta P \Psi_{k\text{-}l}$, the solution to which is $\hat{\Psi}_{k\text{-}l} = (\Delta P^T \Delta P)^{-1}\Delta P^T \Delta P_{k\text{-}l}$. In doing so, we make two key assumptions: (i) the ISFs are approximately constant across the $m+1$ measurements and (ii) the regressor matrix has full column rank.

Example 1 (3-Machine 9-Bus System): We illustrate the concepts described above with the Western Electricity Coordinating Council (WECC) 3-machine 9-bus system as shown in Fig. 1. In order to simulate PMU measurements of slight fluctuations in active power injection at each bus, we create times-series data for the active power injection at each bus. In particular, the injection at node i, denoted by P_i, is given by

$$P_i[j] = P^0_i[j] + \sigma_1 P^0_i[j]v_1 + \sigma_2 v_2, \tag{5}$$

where $P^0_i[j]$ is the nominal power injection at node i at instant j, and v_1 and v_2 are pseudorandom values drawn from standard normal distributions with 0-mean and standard deviations $\sigma_1 = 0.1$ and $\sigma_2 = 0.1$, respectively. The first component of variation, $\sigma_1 P^0_i[j]v_1$ represents the inherent fluctuations

TABLE I: Comparison of ISFs obtained for Example 1.

Line	Actual (p.u.)	Model-based (p.u.)	LSE (p.u.)
$\Delta P_{4\text{-}5}$	-0.2970	-0.3196	-0.3022
$\Delta P_{4\text{-}6}$	-0.1734	-0.1804	-0.1749
$\Delta P_{7\text{-}8}$	+0.1838	+0.1804	+0.1830

TABLE II: Comparison of ISFs obtained for Example 2.

Line	Actual (p.u.)		Model-based (p.u.)	WLS Estimation (p.u.)	
	Before	After		$f = 1$	$f = 0.7$
$\Delta P_{4\text{-}5}$	-0.2970	-0.2046	-0.3196	-0.2145	-0.2203
$\Delta P_{4\text{-}6}$	-0.1734	-0.1426	-0.1804	-0.0529	-0.1416
$\Delta P_{7\text{-}8}$	+0.1838	+0.2121	+0.1804	+0.11156	+0.2066

in generation and load, while the second component, $\sigma_2 v_2$, represents random measurement noise.

In this example, 601 sets of synchronized line flow and bus injection data are acquired, i.e., $m = 600$. The pseudo-random active power injection time-series data are plotted in Fig. 2a for a subset of buses. For each set of bus injection data obtained at a particular time instant, we compute the power flow, allowing the slack bus to absorb all power imbalances, and compute the active power flow through line k-l for that time instant. By taking the difference between consecutive line flow measurements, we obtain the vector $P_{k\text{-}l}$ in (3). Similarly, we obtain the regressor matrix on the right-hand side of (3) by taking the differences between consecutive randomly generated bus injection quantities. Suppose a 0.5 p.u. increase is applied to G_2 at bus 2 and the slack bus absorbs the resulting power imbalance. Table I shows a comparison between the corresponding effect on three lines computed from actual power flow solution, linearized model-based approximation, and our proposed measurement-based method. It is evident that our proposed measurement-based approach provides more accurate results than the model-based one. ■

2) Weighted Least-Squares Estimation: As stated previously, one of the assumptions we make in the discussion above is that the ISFs are approximately constant across the estimation time window. One way to eliminate this restriction and to obtain an estimator that is more adaptive to operating changes is to place more importance on recent measurements and less on earlier ones, which may be out-of-date due to possible operating point changes. Hence, we consider a weighted least squares (WLS) estimation problem setting in which the objective function in (4) becomes

$$\min_{\Psi_{k\text{-}l}} \; e^T S e, \tag{6}$$

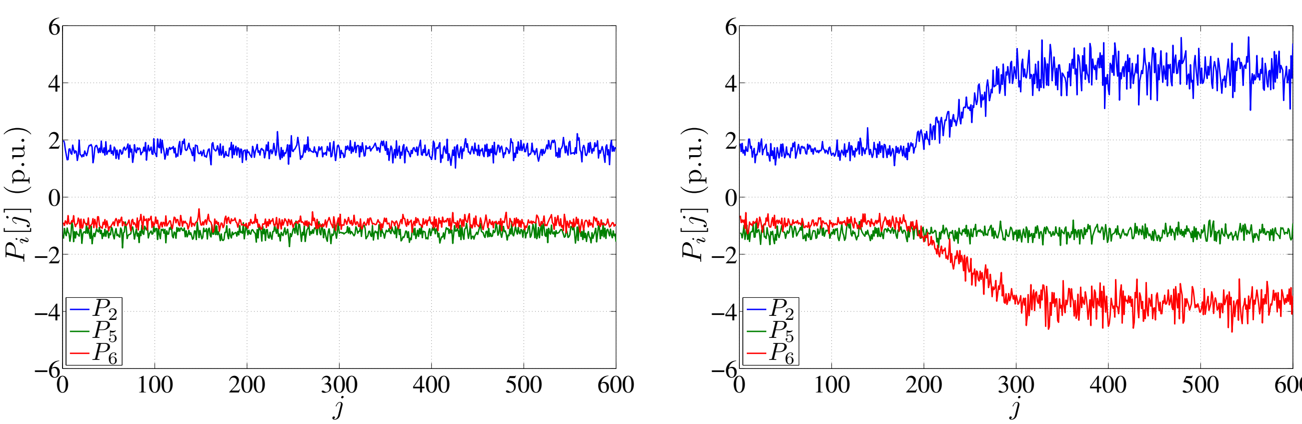
where S is a positive definite symmetric matrix. In our setting, since the elements of the error vector e are uncorrelated, S is a diagonal matrix and $S = \text{diag}[s_1, s_2, \ldots, s_m]$. We preferentially weight the more recent measurements by setting $s_i = f^{m-i}$ for some fixed $f \in (0, 1]$, where f is called a "forgetting" factor. If $f = 1$, then all measurements are given equal weighting, as in the conventional LSE objective function in (4). On the other hand, if $f < 1$, then earlier measurements would not contribute as much to the final estimate $\hat{\Psi}_{k\text{-}l}$ as more recent ones, i.e., earlier measurements are "forgotten" as more data is acquired. This is especially useful for the case in which the system experiences an operating point change during the time window in which measurements are obtained.

3) Recursive Least-Squares Estimation: In practical implementation, since measurements would be obtained sequentially, we use recursive least squares (RLS) scheme to solve the estimation problem and update the estimate as more data is acquired. As such, we consider one set of measurements (or one row in (3)) $\Delta P_{k\text{-}l}[j] = \Delta P[j]\Psi_{k\text{-}l}$ at a time, where $\Delta P[j]$ denotes the k^{th} row of ΔP. Then, $\hat{\Psi}_{k\text{-}l}[j]$, the k^{th} ISF estimate, can be obtained via the following recursive relation:

$$\hat{\Psi}_{k\text{-}l}[j] = \hat{\Psi}_{k\text{-}l}[j-1] + Q^{-1}[j]\Delta P[j] \Big(\Delta P_{k\text{-}l}[j] - \Delta P[j]\hat{\Psi}_{k\text{-}l}[j-1]\Big), \tag{7}$$

where $Q[j] = fQ[j-1] + \Delta P^T[j]\Delta P[j]$ and $Q[1] = 0$.

Example 2 (3-Machine 9-Bus System): We illustrate the use of the forgetting factor described above with the 3-machine 9-bus system used in Example 1. And as in Example 1, we simulate PMU measurements of active power injection at each bus using (5). In this example, however, the load at bus 6 linearly increases by 2.8 p.u. over the span of 120 measurements, with the generation at bus 2 also increasing commensurately



(a) Example 1: operating point does not change.

(b) Example 2: change in real power injections at buses 2 and 6.

Fig. 2: Pseudo-random real power injection time-series data for buses 2, 5, and 6.

TABLE III: Comparison of change of active power line flows with outage in line $l_{4\text{-}5}$.

Line	Actual (p.u.)	Model-based (p.u.)	LSE (p.u.)
$\Delta P_{1\text{-}4}$	0.0493	0.0	0.0293
$\Delta P_{5\text{-}7}$	-0.4068	-0.4094	-0.4351
$\Delta P_{4\text{-}6}$	0.4586	0.4094	0.4387
$\Delta P_{6\text{-}9}$	0.4509	0.4094	0.4345
$\Delta P_{7\text{-}8}$	-0.4619	-0.4094	-0.4595
$\Delta P_{3\text{-}9}$	0.0	0.0	0.0
$\Delta P_{8\text{-}9}$	-0.4579	-0.4094	-0.4538
$\Delta P_{2\text{-}7}$	0.0	0.0	0.0

TABLE IV: Comparison of change in active power line flows with outage in line $l_{8\text{-}9}$.

Line	Actual (p.u.)	Model-based (p.u.)	LSE (p.u.)
$\Delta P_{1\text{-}4}$	0.0071	0.0	0.0027
$\Delta P_{4\text{-}5}$	0.2374	0.2410	0.2301
$\Delta P_{5\text{-}7}$	0.2349	0.2410	0.2297
$\Delta P_{4\text{-}6}$	-0.2303	-0.2410	-0.2274
$\Delta P_{6\text{-}9}$	-0.2290	-0.2410	-0.2247
$\Delta P_{7\text{-}8}$	0.2458	0.2410	0.2441
$\Delta P_{3\text{-}9}$	0.0	0.0	0.0
$\Delta P_{2\text{-}7}$	0.0	0.0	0.0

by an equal amount, representing an operating point change, i.e.,

$$P_6^0[j] = \begin{cases} -0.9 \text{ p.u.} & \text{if } 0 < j \leq 180 \\ -0.9 - \frac{2.8(j-180)}{120} \text{ p.u.} & \text{if } 180 < j \leq 300 \\ -3.7 \text{ p.u.} & \text{if } 300 < j \leq 600 \end{cases}$$

and

$$P_2^0[j] = \begin{cases} 1.63 \text{ p.u.} & \text{if } 0 < j \leq 180 \\ 1.63 + \frac{2.8(j-180)}{120} \text{ p.u.} & \text{if } 180 < j \leq 300 \\ 4.43 \text{ p.u.} & \text{if } 300 < j \leq 600 \end{cases}.$$

In Fig. 2b, the pseudo-random real power injection time-series data at buses 2, denoted by $P_2[j]$, and 6, denoted by $P_6[j]$, are depicted with the blue and red traces, respectively. The green trace in Fig. 2b represents the power injection time-series for bus 5. Data generated for other buses are omitted as they are similar to $P_5[j]$. Again, for each set of bus injection data, we compute the power flow, with the slack bus absorbing all power imbalances, and the active power flow through each line for that particular time. As in Example 1, suppose a 0.5 p.u. increase is applied to G_2 at bus 2 with the slack bus absorbing the resulting power imbalance. Table II shows a comparison between the corresponding effect on three lines computed from the actual power flow solution (both before and after the operating point change), the linearized model-based approximation, and our proposed measurement-based method, with a forgetting factor $f = 1$ and $f = 0.7$. Columns 2 and 3 in Table II depict the changes in line flows due to a 0.5 p.u. generation increase in G_2 before and after the operating point change, respectively. It is evident from Table II that the RLS estimation scheme (column 5) with $f = 0.7$ is able to track the ISFs after operating point change with significant higher accuracy than both the model-based solution and the conventional LSE with $f = 1$. ■

B. Computation of Other Distribution Factors

Once the ISFs are obtained via online estimation, we can compute other relevant linear sensitivity distribution factors. In this section, we describe the algorithm to obtain PTDFs and subsequently LODFs.

1) Power Transfer Distribution Factor (PTDF): The PTDF, denoted by $\Phi_{k\text{-}l}^{k'l'}$, approximates the sensitivity of the active power flow on line k-l with respect to an active power transfer of a given amount of power, $\Delta P_{k'l'}$, from bus k' to l' [7]. The PTDF can be computed as a superposition of an injection at bus k' and a withdrawal at bus l', where the slack bus accounts for the power imbalance in each case. Thus,

$$\Phi_{k\text{-}l}^{k'l'} = \Psi_{k\text{-}l}^{k'} - \Psi_{k\text{-}l}^{l'},$$

where $\Psi_{k\text{-}l}^{k'}$ and $\Psi_{k\text{-}l}^{l'}$ are the linear sensitivities of active line flow in line k-l with respect to injections at buses k' and l', respectively.

2) Line Outage Distribution Factor (LODF): The LODF, denoted by $\Xi_{k\text{-}l}^{k'\text{-}l'}$, approximates the active power flow change in line k-l due to the outage of line k'-l' as a percentage of pre-outage active power flow through k'-l' [7]. Suppose line k-l is connects bus k to l, while line k'-l' connects bus k' to l'. In this case, $\Xi_{k\text{-}l}^{k'\text{-}l'}$ is expressed as

$$\Xi_{k\text{-}l}^{k'\text{-}l'} = \frac{\Phi_{k\text{-}l}^{k'l'}}{1 - \Phi_{k'\text{-}l'}^{k'l'}} = \frac{\Psi_{k\text{-}l}^{k'} - \Psi_{k\text{-}l}^{l'}}{1 - (\Psi_{k'\text{-}l'}^{k'} - \Psi_{k'\text{-}l'}^{l'})}.$$

Example 3 (3-Machine 9-Bus System): As in Example 1, we consider the system in Fig. 1. In this example, we examine two scenarios, the first with outage in line $l_{4\text{-}5}$ and the second with outage in line $l_{8\text{-}9}$. In each scenario, we compare the change in actual power flowing across each remaining line due to the line outage to the corresponding quantities computed from the estimated ISFs and the model-based approximate ISFs. In general, as shown in Tables III and IV, the measurement-based approach outperforms the model-based one. ■

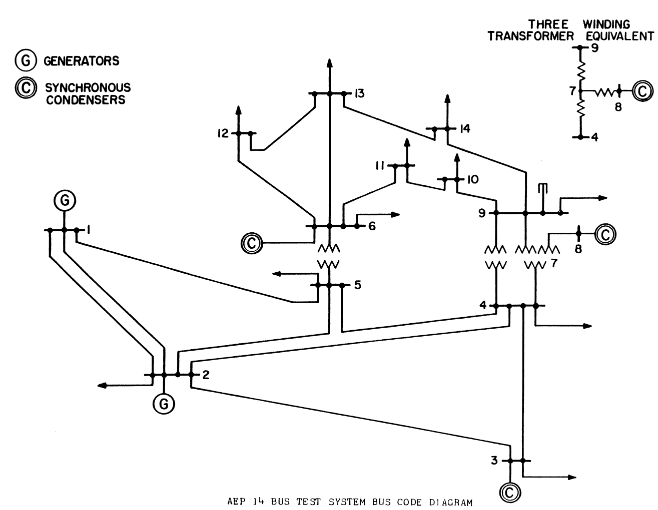


Fig. 3: Network topology for IEEE 14-bus system.

TABLE V: Contingency analysis on base case system.

Line	Actual (p.u.)	Model-based (p.u.)	LSE (p.u.)
$\Delta P_{1\text{-}2}$	0.2019	0.1758	0.1962
$\Delta P_{1\text{-}5}$	-0.1762	-0.1758	-0.1643
$\Delta P_{2\text{-}3}$	0.1530	0.1465	0.1494
$\Delta P_{2\text{-}4}$	0.3185	0.3047	0.3075
$\Delta P_{2\text{-}5}$	-0.2816	-0.2754	-0.2698
$\Delta P_{3\text{-}4}$	0.1423	0.1465	0.1409
$\Delta P_{4\text{-}7}$	-0.0991	-0.0910	-0.1000
$\Delta P_{4\text{-}9}$	-0.0566	-0.0531	-0.0571
$\Delta P_{5\text{-}6}$	0.1615	0.1441	0.1535
$\Delta P_{6\text{-}11}$	0.0981	0.0882	0.0938
$\Delta P_{6\text{-}12}$	0.0127	0.0099	0.0120
$\Delta P_{6\text{-}13}$	0.0507	0.0459	0.0477
$\Delta P_{7\text{-}8}$	0.0	0.0	0.0
$\Delta P_{7\text{-}9}$	-0.0991	-0.0910	-0.1000
$\Delta P_{9\text{-}10}$	-0.0947	-0.0882	-0.0952
$\Delta P_{9\text{-}14}$	-0.0610	-0.0559	-0.0619
$\Delta P_{10\text{-}11}$	-0.0948	-0.0882	-0.0939
$\Delta P_{12\text{-}13}$	0.0125	0.0099	0.0126
$\Delta P_{13\text{-}14}$	0.0619	0.0559	0.0602

TABLE VI: Contingency analysis on modified system with removal of $l_{10\text{-}11}$.

	Pre-contingency	**Post-contingency**		
Line	Actual (p.u.)	Actual (p.u.)	Model-based (p.u.)	LSE (p.u.)
$P_{1\text{-}2}$	1.5684	0.8004	1.7492	1.8084
$P_{1\text{-}5}$	0.7582	0.5610	0.5774	0.5769
$P_{2\text{-}3}$	0.7295	0.9065	0.8803	0.9052
$P_{2\text{-}4}$	0.5617	0.9268	0.8751	0.9218
$P_{2\text{-}5}$	0.4172	0.0933	0.1339	0.1146
$P_{3\text{-}4}$	-0.2358	-0.0717	-0.0850	-0.0700
$P_{4\text{-}5}$	-0.6124	0.0	0.0	0.0
$P_{4\text{-}7}$	0.2801	0.2107	0.1864	0.2148
$P_{4\text{-}9}$	0.1597	0.1201	0.1051	0.1225
$P_{5\text{-}6}$	0.4452	0.5626	0.5935	0.5604
$P_{6\text{-}11}$	0.0351	0.0351	0.1259	0.0403
$P_{6\text{-}12}$	0.0887	0.1125	0.0989	0.1109
$P_{6\text{-}13}$	0.2094	0.3029	0.2567	0.2972
$P_{7\text{-}8}$	0.0	0.0	0.0	0.0
$P_{7\text{-}9}$	0.2801	0.2107	0.1864	0.2148
$P_{9\text{-}10}$	0.0903	0.0904	-0.0004	0.0899
$P_{9\text{-}14}$	0.0544	-0.0545	-0.0031	-0.0477
$P_{12\text{-}13}$	0.0268	0.0501	0.0370	0.0489
$P_{13\text{-}14}$	0.0976	0.2116	0.1551	0.2053

III. RESULTS

With a model of the system, power system operators obtain the linear sensitivity DFs offline and use them in real-time contingency analysis. In particular, operators must ensure that the power system remains operable with an outage in any single facility, a condition know as N-1 security. For example, LODFs indicate the portion of pre-outage flow that is redistributed onto remaining lines upon outage of the former. Using current active power line flows and LODFs, we can estimate the flow through all other lines if there were an outage on one line. If no line constraints are violated with any single line outage, we conclude the system is N-1 secure with respect to line outages. The pre-calculated model-based LODFs may not, however, be accurate if the system operating point and network topology deviate sufficiently far away from those at which the sensitivity factors were computed.

In this section, we apply the ideas presented previously in contingency analysis for the IEEE 14-bus system, the network topology of which is shown in Fig. 3. In this case study, we compute the LODFs offline using the original model and compare the accuracy of these compared to the DFs estimated online in contingency analysis. Next, we suppose line $l_{10\text{-}11}$ fails in an open-circuit fashion but is undetected by system operators. This scenario is realistic since operators may not have full knowledge of current conditions in neighboring control areas, one of which could contain $l_{10\text{-}11}$. For these studies, we construct net active power injection "measurements" as in Example 1, again with $\sigma_1 = \sigma_2 = 0.1$. And line flows are inferred from power flows computed for each set of injections.

A. Comparison of DFs in base case contingency analysis

For brevity, we present contingency analysis results for only the hypothetical case that line $l_{4\text{-}5}$ fails in Table V. As in the 3-machine 9-bus case in Example 2, the line flow predictions obtained using the model-based approximation and the measurement-based estimation appear almost equally effective when compared to the exact solution. Actually, for contingency under consideration here, the average deviation away from the exact power flow solution is 0.0069 p.u. using the model-based approximation method, while the average error is 0.0034 p.u. using the measurement-based estimation method, about half that obtained by the former traditional method. In this case, the accuracy of the traditional approach seems comparable to the LSE method. However, the proposed LSE method, due to its adaptability to changing operating points and network topology, is especially advantageous over the traditional method for a case in which the system no longer matches the model that was used to compute the DFs, as we illustrate next.

B. Comparison of DFs with undetected line outage

Suppose a line outage occurs in $l_{10\text{-}11}$, unbeknownst to system operators, perhaps because it is located in a neighboring control area. Contingency analysis continues to be conducted on the system using the LODFs computed based on the system model, which is no longer accurate due to the undetected line outage. For the revised system with line outage, we present contingency analysis results in the hypothetical case in which line $l_{4\text{-}5}$ fails in Table VI. More specifically, we compare between pre- and post-contingency (of $l_{4\text{-}5}$) actual line flows, model-based computed line flows, and measurement based estimated line flows. A rough visual inspection of the post-contingency line flows reveals that the LSE prediction (column 5), which is updated by taking up-to-date measurements of bus injection and line flow incremental changes, is much closer to the actual post-contingency flow (column 3) than the model-based approximations (column 4). In fact, for the $l_{4\text{-}5}$ contingency under consideration, the average deviation away from the exact power flow solution is 0.0346 p.u. using the model-based approximation approach, while the average error is 0.0052 p.u., almost an order of magnitude smaller.

Further, suppose that the thermal limit of lines $l_{2\text{-}3}$ and $l_{13\text{-}14}$ are 0.9 p.u. and 0.2 p.u., respectively. We note that the actual post-contingency flow on these lines would be 0.9065 p.u. and 0.2107 p.u., both violating their respective thermal limits. While the measurement-based LSE method captures these overloads, the model-based LODFs are out-of-date and do not alarm operators to the potential problem if the contingency on $l_{4\text{-}5}$ were to occur. On the other hand, suppose the thermal line limit on $l_{6\text{-}11}$ is 0.1 p.u. The post-contingency flow predicted by the model-based method is 0.1259 p.u., over the prescribed limit, while the actual flow is only 0.0351 p.u. In this case, the model-based LODFs causes a misdetection, while the LSE method approximates the actual post-contingency flow much more closely.

IV. Conclusions

In this paper, we presented a method to estimate DFs by employing PMU measurements collected in real-time that does not rely on the system power flow model. Beyond eliminating the reliance on the system model, as shown in the examples and the case study in Sections II and III, the proposed measurement-based approach provides more accurate results than the conventional model-based approximations. Further, we employ recursive least-squares estimation with a forgetting factor so that the estimator adapts to changing operating points in the system and is able to accurately estimate ISFs of the system in its current state, as shown in Example 2.

Key advantages of the proposed method include the elimination of reliance of system models and corresponding accuracy and resilience to unexpected system topology and operating point changes. Moreover, the framework provides opportunity to explore distributed algorithms to solve the problem, using only local PMU data.

V. Future Work

In theory, even if we only wished to obtain a subset of ISFs for a particular line, we still need to obtain active power injection measurements at all n buses. In practice, however, buses that are geographically far way from the line are unlikely to significantly affect the active power flow through the line. Further work includes accurate estimation of DFs in the presence of corrupted measurements or the availability of only a subset of measurements. Also, the measurement-based method necessitates an over-determined system. Hence, we would like to devise algorithms that estimate the DFs accurately using fewer measurements, which would increase the estimator's responsiveness to system changes.

VI. Access to Products

The products of this work include algorithms and implementations thereof in MATLAB. The code files may be acquired from authors via Email request.

VII. Acknowledgment

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Resiliency for High Impact, Low Frequency Events (6.1)

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***Abstract*—Geomagnetic disturbances (GMDs) have the potential to severely disrupt electric grids worldwide. However, prior to the start of this task power engineers had limited ability to study the impacts of GMDs on their systems. In this task we have worked in coordination with key stakeholders (NERC, EPRI, government, manufacturers and individual utilities) to development a methodology for integrating GMD assessment into the power flow and transient stability applications. We have also developed a methodology for GMD sensitivity analysis. Results from this work have been integrated into commercial tools and are now available to the electric utility industry.**

I. Introduction

While there are a number of different definitions for resiliency, probably the one most germane to electric grids is the ability of a system to gradually degrade under increasing system stress, and then to return to its pre-disturbance condition when the disturbance is removed. A resilient power grid should not experience a sudden, catastrophic system collapse, but rather should be able to adapt to "keep the all the lights on" under small to moderate system disturbances, and to keep at least some level of system service even in the event of severe system disturbances.

The focus of this task was to consider resiliency with respect to high impact, low frequency (HILF) events. Of course, the electric grid can be subjected to many types of events that result in substantial loss of electric service. Examples include ice storms, tornados, hurricanes and earthquakes. And certainly for those affected, these would be considered high impact events.

However there is another class of events that have the potential for even more catastrophic and potentially much longer damage to the electric grid. These were identified by North American Electric Reliability Corporation (NERC) and U.S. Department of Energy (DOE) in [1] as 1) cyber or physical coordinated attack, 2) pandemic, and 3) geomagnetic disturbance/electro-magnetic pulse. Yet even within this field the scope was still quite broad, and at least one, cyber security, was already being covered by separately funded DOE efforts.

So the task focused on just one of these issues, the impact of a severe geomagnetic disturbance (GMD) on the electric grid. The electric grid impact of a large GMD has been the subject of several recent publications in which it is postulated that a GMD event of magnitude similar to the one that occurred in May 1921 could result in large-scale blackouts and potential damage to power system equipment [1], [2], [3], [4]. A storm in March 1989, which was much smaller than the one in 1921, resulted in a blackout of the entire province of Quebec, while a GMD in 1859 had electric field magnitudes estimated to be ten larger than the 1989 event.

As noted in [5], the potential for GMDs to interfere with power grid operation has been known since at least the early 1940's, with its ability to interfere with communication systems (i.e., the telegraph) noted as early as the 1850's. The basic mechanism for this interference is GMDs cause variations in the earth's magnetic field. These changes induce quasi-dc electric fields (usually with frequencies much below 1 Hz) in the earth with the magnitude and direction of the field GMD event dependent. These electric fields then cause geomagnetically induced currents (GICs) to flow in the earth's crust (with depths to hundreds of kms), the earth's atmosphere, and in other conductors such as the high voltage electric transmission grid. In the high voltage transformers the quasi-dc GICs produce an offset on the regular ac current that can lead to half-cycle saturation, resulting in increased transformer heating and reactive power losses [5].

While a relatively old problem, GMD has been an area of active interest by the electric utility industry in recent years. For example, in February 2012 NERC issued a special reliability assessment report on GMDs [6], which notes that there are two primary risks associated with GICs in the bulk electric system. The first is the potential for damage to transmission system assets, primarily the high voltage transformers. The second is the loss of reactive power support leading to the potential for a voltage collapse.

In pursuing this research we have worked in close collaboration with the key stakeholders in North America (NERC, EPRI, government, hardware and software manufacturers, and individual utilities) to address issues that matched their needs and our expertise. The focus of our work has been the development of methodologies to help power engineers study the impact of GMDs on their systems, with a particular focus on the power flow and transient stability applications. Hence we focused on the second issue identified by NERC: the potential for increased GMD related reactive power losses to cause a power system voltage collapse.

This paper is organized as follows. The next section discusses integration of GMD assessment into the power flow, with the following section looking at large-scale system issues. Section IV then discusses sensitivity analysis, while Section V briefly considers short term voltage stability.

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II. GIC Power Flow Modeling Methodology

The inclusion of the impact of GICs in the power flow was first described in [7] with later consideration for large system studies in [8]. Here we build on these results, presenting a unified approach with the GIC calculations integrated into the power flow solution [9]. Consider a standard m bus power flow model (e.g., positive sequence) in which the m buses are grouped into s substations; let n = m+s. Because the GICs change slowly (with frequencies much below 1 Hz), from a power flow analysis perspective they can be considered as dc.

How they flow through the power grid can be determined by solving

$$\mathbf{V} = \mathbf{G}^{-1}\mathbf{I} \tag{1}$$

where **G** is an n by n symmetric matrix similar in form to the power system bus admittance matrix, except 1) it is a real matrix with just conductance values, 2) the conductance values are determined by the parallel combination of the three individual phase resistances, 3) **G** is augmented to include the substation neutral buses and substation grounding resistance values, 4) transmission lines with series capacitive compensation are omitted since series capacitors block dc flow, and 5) the transformers are modeled with their winding resistance to the substation neutral and in the case of autotransformers both the series and common windings are represented. Of course for large systems **G** is quite sparse and hence (1) can be solved with computational effort equivalent to a single power flow iteration. When solved the voltage vector **V** contains entries for the s substation neutral dc voltages and the m bus dc voltages.

The vector **I** models the impact of the GMD-induced electric fields as Norton equivalent dc current injections. Two main methods have been proposed for representing this electric field variation in the power grid: either as dc voltage sources in the ground in series with the substation grounding resistance or as dc voltage sources in series with the transmission line resistances [7], [10]. In both approaches these Thevenin equivalent voltages are converted to Norton equivalent currents that are then used in **I**. In [10] it was shown that while the two methods are equivalent for uniform electric fields, but only the line approach can handle the non-uniform electric fields that could occur in a real GMD event.

Using the approach of [10] to calculate the GMD-induced voltage on transmission line k, U_k, the electric field is just integrated over the length of the [11],

$$U_k = \int_{\mathcal{R}} \overline{E} \cdot d\overline{l} \tag{2}$$

where $\mathcal{R}$ is the geographic route of transmission line k, $\overline{E}$ is the electric field along this route, and $d\overline{l}$ is the incremental line segment. Note, here we use the symbol U for the voltages induced to the lines to differentiate from the bus and substation voltages in (1).

If the electric field is assumed to be uniform over the route of the transmission line then (2) is path independent and can be solved just knowing the geographic location of the transmission line's terminal buses. In this case (2) can be simplified to

$$U_k = E_k\, L_k \cos(\theta_{k,E} - \theta_{k,L}) \tag{3}$$

in which E_k is the magnitude of the electric field (V/km), $\theta_{k,E}$ is its compass direction (with north defined as 0 degrees), L_k is the distance between the two terminal substations of the line, and $\theta_{k,L}$ is the compass direction from the substation of the arbitrarily defined "from" bus i to the substation of the "to" bus j.

Define the electric field tangential to the line as

$$E_{k,T} = E_k \cos(\theta_{k,E} - \theta_{k,L}) \tag{4}$$

Then using (4), (3) simplifies to

$$U_k = E_{k,T}\, L_k \tag{5}$$

The degree of solution error introduced by assuming a uniform field over a line's route is an area of current debate, with a uniform field suggested as adequate for planning studies in [6] (but with consideration of multiple directions). However, the geoelectric field calculations can be quite involved, potentially requiring detailed models of the earth's crust conductivity, and as noted in [12], [10], [13] can be significantly influenced by the nearby presence of salt water.

It is important to note that assuming the electric field is uniform over the path of a particular line is quite different than assuming the field is uniform throughout the study footprint. Because GMDs are continental in scope, the variation in the electric field over most line lengths would likely not be significant. In the case of long lines, the voltage can be approximated by dividing the line into segments, and assuming a uniform field over the individual segments, and then summing the results. Also, as we presented in [14], which electric fields need to be modeled in detail is driven in part by the conductivity structure of the electric transmission system.

To further the formulation it is useful to modify (1) to write the input in terms of the vector of electric field magnitudes tangential to each of the K transmission lines in the system,

$$\mathbf{V} = \mathbf{G}^{-1}\mathbf{B}\,\mathbf{E}_T \tag{6}$$

where $\mathbf{E}_T$ is a K-dimensional real vector with entries giving the magnitude of the electric field tangential to each line, as per (4). **B** is an n by K real matrix in which each column, corresponding to line k, has non-zeros only at the location of the "from" end bus i and the "to" end bus j; the magnitude of these values is the line's conductance, g_k, multiplied by the distance between the line's terminal, L_k, with a sign convention such that the "from" end has a positive value, and the "to" end a negative value.

To illustrate, consider the three substation (s=3), four bus (m = 4) system shown in Fig. 1 with Bus 1 in Substation A, Buses 2 and 3 in Substation B and Bus 4 in Substation C. Assume all the substations have grounding resistance 0.2 **Ω**, that the Bus 1 generator has an implicitly modeled generator step-up (GSU) transformer with resistance of 0.15 Ω/phase on the high (wye-grounded) side (0.05 Ω for the three phases in parallel), and that the Bus 4 generator has a similar GSU transformer with 0.15 Ω/phase. There is a 345 kV transmission line between Buses 1 and 2 with resistance of 3 Ω/phase, and a 500 kV line between Buses 3 and 4 with a resistance of 2.4 Ω/phase. Buses 2 and 3 are connected through a wye-grounded autotransformer with resistance of 0.04 Ω/phase for the common winding and 0.06 Ω/phase for the series winding.[1]

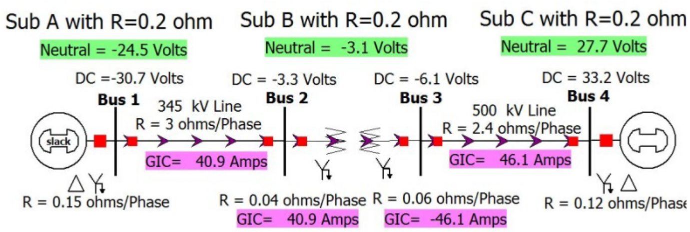

Fig. 1. Three substation, four bus GIC example

Assume the substations are at the same latitude, with Substation A 150 km to the west of B, and C 150 km to the east of B. With a 1 V/km assumed eastward GMD induced electric field (parallel to the lines), (5) gives induced voltages of 150V for each of the lines. The system **G** matrix is shown in Table 1 and the **B** matrix in Table 2. With an assumed eastward electric field of 1 V/km the voltage vector **V** values shown in Table 3.

TABLE I
G MATRIX (IN SIEMENS) FOR THE FOUR BUS SYSTEM

	SubA	SubB	SubC	1	2	3	4
SubA	25	0	0	-20	0	0	0
SubB	0	80	0	0	-75	0	0
SubC	0	0	30	0	0	0	-25
1	-20	0	0	21	-1	0	0
2	0	-75	0	-1	126	-50	0
3	0	0	0	0	-50	51.25	-1.25
4	0	0	-25	0	0	-1.25	26.25

TABLE II
$\mathbf{B}^T$ MATRIX (IN SIEMENS-KM) FOR THE FOUR BUS SYSTEM

Line ↓	SubA	SubB	SubC	1	2	3	4
1 to 2	0	0	0	150	-150	0	0
3 to 4	0	0	0	0	0	187.5	-187.5

TABLE III
$\mathbf{V}^T$ VECTOR (IN VOLTS) FOR THE FOUR BUS SYSTEM

	SubA	SubB	SubC	1	2	3	4
Voltage	-24.5	-3.1	27.7	-30.7	-3.3	-6.1	33.2

Once the voltages are known, the GICs flowing in the transmission lines and transformers can be determined by just solving the dc circuit equation for each line, including the GMD induced series voltage for each of the transmissions lines. A potential point of confusion in interpreting the results of the GIC calculations is to differentiate between the per phase currents GICs in transmission lines and transformers, and the total three phase GICs in these devices. Since the three phases are in parallel, the conversion between the two is straightforward with the total current just three times the per phase current. The convention commonly used for GIC analysis is to use the per phase current for transformers and transmission lines, and the total three phase current for the substation neutral current. Thus for the Fig. 1 system the current flowing the Buses 1 and 2 transmission line is

$$\frac{E_{21}+V_1-V_2+}{3\ \Omega/\text{phase}} = \frac{(150-30.67+3.34)}{3} = 40.9 \text{ A / phase} \qquad (7)$$

The coupling between the GIC calculations and the power flow is the GIC-induced reactive power loss for each transformer r is usually modeled as a linear function of the effective GIC through the transformer [5], [15], [16] with [17] making the observation that these reactive power losses vary linearly with terminal voltage,

$$Q_{GIC,r} = V_{pu,r} K_r I_{Effective,r} \qquad (8)$$

where $Q_{GIC,r}$ is the additional reactive power loss for the transformer (in Mvar), $V_{pu,r}$ is the per unit ac terminal voltage for the transformer, and K_r is a transformer specific scalar with units Mvars/amp.

The value of $I_{Effective,,r}$ used in (8) is an “effective” per phase value that depends on the type of transformer. In the simplest case of a grounded wye-delta, such as is common for a GSU transformers, $I_{Effective,r}$ is straightforward – just the current in the grounded (high-side) winding. For transformers with multiple grounded windings and autotransformers the value of I_{GIC} depends upon the current in both coils [7]. Here we use the approach of [16] and [9],

$$I_{Effective,r} = \left| I_{GICH,r} + \frac{I_{GICL,r}}{a_{t,r}} \right| \qquad (9)$$

where $I_{GICH,r}$ is the per phase GIC going into the high side winding (i.e., the series winding of an autotransformer), $I_{GICL,r}$ is the per phase GIC going into the low side of the transformer, and $a_{t,r}$ is the standard transformer turns ratio (high voltage divided by low voltage).

To facilitate the derivation of the transformer effective current sensitivities discussed in the next section, it is useful to define a column vector $\mathbf{C}_r$ of dimension n such that

$$I_{\text{Effective,r}} = \left|\mathbf{C}_r \mathbf{V}\right| = \left|\mathbf{C}_r \mathbf{G}^{-1} \mathbf{B} \mathbf{E}_T\right| \qquad (10)$$

where $\mathbf{C}_r$ is quite sparse, containing the per phase conductance values relating the GIC bus and substation dc voltages to the current. For a GSU transformer with a single grounded coil going between bus i and substation neutral s with conductance g_{is}, the only nonzeros in $\mathbf{C}_r$ would be g_{is} at the bus i position, and $-g_{is}$ at the substation neutral s position.

The **C** vectors for the three transformers in the four bus example are given in Table 4. Using these values and **V** from Table 3 the $I_{effective}$ values of 40.9 amps (Bus 1 GSU), 46.1 amps (Bus 4 GSU) and 17.9 amps (Bus 2 to 3

[1] Since the concept of per unit plays no role in GIC determination, resistance values are expressed in Ohms (Ω), current is in amps (A), and the dc voltages are given in volts (V).

Autotransformer) are readily verified.

TABLE IV
C VECTORS (IN SIEMENS) FOR THE FOUR BUS SYSTEM; NOTE VALUES ARE CONDUCTANCE PER PHASE AS OPPOSED TO THE THREE PHASE VALUES USED IN **G**

Transformer	SubA	SubB	SubC	1	2	3	4
Bus 1 GSU	-6.7	0	0	6.7	0	0	0
Bus 4 GSU	0	0	-8.3	0	0	0	8.3
Bus 2-3	0	-17.25	0	0	12.1	5.2	0

III. LARGE-SCALE ISSUES ASSOCIATED WITH THE DETERMINATION OF GICS

From a conceptual point of view, determining the GICs in a large system is very similar to the methodology introduced with the four bus example. That is, knowledge of a GMD storm scenario and an appropriate power system model allows one to determine the current vector and conductance matrix in (1). This equation is then solved to determine the voltage vector. From a computational perspective this solution is relatively trivial, taking less than one second for the 62,000 bus model North America Eastern Interconnect model (EI) (significantly less time than the associated power flow solution). The voltage vector is then used to determine the $I_{Efffective}$ for all of the system transformers. Then (8) is used to determine the increased transformer reactive power demand.

All of these steps just involve the solution of linear equations so they are fast and reliable. For some GIC studies just calculating these values is sufficient. However, if desired, the power flow equations could also be solved with the increased reactive power loading at each transformer modeled as a reactive current load. If this reactive load is high it can lead to a stressed power flow and eventually nonconvergence.

Much of the data needed for GIC analysis is contained in the standard power flow models. This includes the network topology, bus voltage levels, resistance of the transmission lines and the presence of transmission line series compensation. For transformers, the power flow model contains the total series resistance of the transformer but does not typically contain the resistance of the individual windings. When available the actual winding resistance should be used. Otherwise the individual coil winding resistances can be estimated by recognizing that the total resistance is not equally split between the two windings. Rather, since the high voltage winding has more turns and lower amps, its resistance will be higher. Referring to (11), a ballpark ratio of the high to low winding resistance is $(a_t)^2$ for a regular transformer and $(a_t\text{-}1)^2$ for an autotransformer. Thus for a non-autotransformer the winding resistances can be estimated using

$$\frac{R_{pu}}{R_{Base,HighSide}} = R_{HighSide} + a_t^{\,2} R_{LowSide} \qquad (11)$$

and assuming the magnitude of both terms on the right-hand side of (11) are equal; a slightly modified equation is used for autotransformers [9].

One key data structure needed for GIC analysis is substation records. While some power flow packages have long contained explicit substation records, others do not. Substation records are needed to 1) modeling the grounding resistance required for the construction of **G** in (1), 2) represent the substation neutral voltages and current injections in the **V** and **I** vectors of (1), and 3) provide the geographic locations needed for the calculation of dc line voltages.

The substation grounding resistance field is used to represent the effective grounding resistance of the substation, consisting of its grounding mat and the ground paths emanating out from the substation such as due to shield wires grounding. This resistance depends upon several factors including the size of the substation (with larger substations generally having a lower value) and the resistivity of the ground (with substations in rocky locations having higher values). Ballpark values for low resistivity soil are usually substantially below 0.5Ω for a 230kV and above substations, and between 1 and 2 Ω for the lower voltage substations.

For this project we helped to get this methodology integrated into one commercial power flow package [18]. This package was then used in conjunction with EPRI and individual utilities to do analysis of twenty bus test system from [11] along utility systems located in both the EI and WECC. The methodology for this analysis was to perform a series of power flow solutions with an assumed increasing electric field in specified directions. The integrated approach calculated the associated GICs, and then solved the power flow with the increased reactive demand modeled at the transformers using (8). The electric field was increased until the point of maximum loadability (i.e., loss of power flow convergence). The analysis was repeated for several different directions. As an example, Fig. 2 visualizes the GICs calculated in the twenty bus case for an east-west field. The yellow arrows show the direction and magnitude of the GICs.

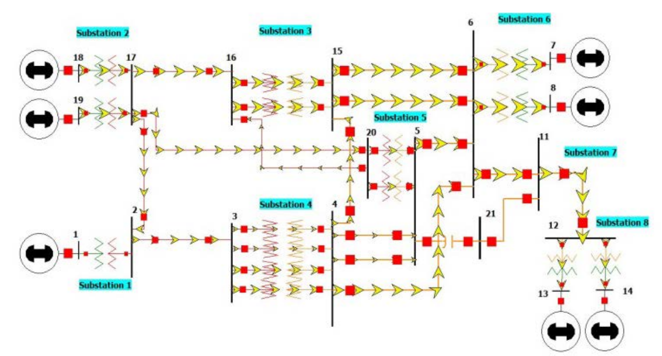

Fig. 2. GICs in twenty bus network for uniform east-west field

IV. SENSITIVITY ANALYSIS

A key concern in performing these power flow studies is to know the sensitivity of the results to the input electric field assumptions. While the impact of GICs could be calculated for an entire interconnect, most utilities would be concerned with the impact on their much smaller footprint. In this section we derive sensitivities to determine which transmission line voltages contribute to the GICs in specified transformers.

Motivated by the optimal power flow control sensitivities in [19], differentiating (10) with respect to the electric field vector input gives a column vector of dimension K,

$$\frac{dI_{\text{Effective,r}}}{d\mathbf{E}_T} = \pm\,\mathbf{C}_r\,\mathbf{G}^{-1}\mathbf{B} = \pm\mathbf{S}_{T,r} \tag{12}$$

with the ± resolved using the sign of the absolute value argument from (10). The interpretation of these results is each entry k in $\mathbf{S}_{T,r}$, $\mathbf{S}_{T,r}[k]$, tells how $I_{Effective}$ for the r[th] transformer would vary for a 1 V/km variation in the electric field tangential to the path of transmission line k.

Then from (10) and (12), and referring back to the direction definitions from (3), it is easy to show

$$\begin{aligned} I_{Effective,r} &= \left|\sum_{k=1}^{K}\left(\mathbf{S}_{T,r}[k]\mathbf{E}_T[k]\right)\right| \\ &= \sum_{k=1}^{K}\left(\mathbf{S}_{T,r}[k]\mathbf{E}[k]\cos(\theta_{k,E}-\theta_{k,L})\right) \end{aligned} \tag{13}$$

in which the elements of the summation indicate the contribution to $I_{Effective}$ for the r[th] transformer provided by each line in the system for the case of a (potentially) non-uniform field. In the case of a uniform field applied to the entire case then $\theta_{k,E}$ will be the same for all the transmission lines.

Several observations are warranted. First, from a computational perspective (12) is quite straightforward to evaluate. Since **G** is symmetric, once it has been factored $\mathbf{C}_r\,\mathbf{G}^{-1}$ can be solved with just a forward and backward substitution. Second, the magnitude of the entries in $\mathbf{S}_r$ indicate the transmission lines that are most important in the contributing to $I_{Effective,r}$ for a uniform field, with the simple scaling from (13) generalizing to the non-uniform case. Hence a more accurate knowledge of the electric field associated with the most sensitive lines is warranted.

Third, since during a particular GMD the field direction could change rapidly, and certainly may not be the same everywhere, the 1-norm of $\mathbf{S}_{T,r}$ actually provides the worst case scenario for a uniform electric field storm. That is, the sum of the absolute values of the elements of $\mathbf{S}_{T,r}$ tell the absolute maximum value for $I_{Effective,r}$ in the unlikely event that a 1 V/km storm was oriented tangentially to all the transmission lines. Or, perhaps more usefully, tangential to the lines most important to transformer k.

Fourth, the previous observation can be generalized for the non-uniform case by defining

$$I_{max,r} = \sum_{k=1}^{K}\left(\left|\mathbf{S}_{\mathbf{T,r}}[k]\right|\mathbf{E}[k]\right) \tag{14}$$

in which each of the elements in the summation tells the maximum GIC that could be contributed by each transmission line when subjected to the specified non-uniform field aligned tangentially to the line. Finally, this analysis can easily be extended to allow consideration of multiple transformers simultaneously with details given in [14]

Results from such sensitivity analysis applied to large cases indicate that the transformer GICs are usually supplied by a small number of close by transmission lines. The ramification is that detailed knowledge of the GMD-induced electric fields is probably needed only for transmission lines within or nearby to the study footprint. This is a quite useful result since in some geographic locations, such as near salt water or in locations with varying crust conductivity, the field calculations can be involved. For footprints outside such regions simpler models, perhaps uniform electric fields, could be used. Even for footprints containing more complex geographic locations, the more detailed electric field calculations are only needed for the footprint area.

V. Short Term Voltage Stability Considerations

The power flow provides a quasi-steady state analysis in which dynamics with time constants of less than several minutes are assumed to have reached their equilibrium point values, whereas the variables associated with slower time constants are assumed to be constant. For example, in the power flow generators are modeled as PV buses in which generator exciter dynamics are considered sufficiently fast to maintain a constant terminal voltage magnitude, and load tap changing transformers (LTCs) are assumed to move their taps to maintain a specified voltage setpoint.

In embedding the impact of GICs in the power flow, the implicit assumption is that GICs vary sufficiently slowly that such a quasi-steady state analysis is appropriate. However, it may not be sufficient because of the potential for much faster changes due to the underlying GMD dynamics. For example, the electric fields sometimes have rise times of approximately 30 seconds [20]. Fast rise times in transformer neutral currents have been observed in measurements (e.g., Figure 1.8 of [8]). A second important consideration is the duration of the elevated electric fields and the subsequent GICs. Extremely high levels are likely to persist for less than 5 minutes, even though a storm itself may last for hours or days [20], [8].

Voltage stability is defined as “the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition” [21]. The two types of voltage stability classifications are according to the size of the disturbance and the duration of the disturbance. Large disturbance voltage stability considers the time domain response of a system after a large disturbance such as a generator outage. The large disturbance in a GMD context is a time variation in the GICs. Small disturbance voltage stability considers system response to small perturbations about a particular operating point.

The second classification type is based on the problem time frame, with short-term voltage stability considering time frames on the order of several seconds, while long-term voltage stability extends the analysis to minutes.

Ongoing research for this project is considering these more dynamic aspects of GMD voltage stability. From this perspective one could consider the power flow analysis as being a small disturbance voltage stability assessment. That is, looking at the static voltage response using a series of snap-shot cases in which the electric field is gradually increased. This work in progress is considering large disturbance voltage stability in which a time-varying GMD disturbance is applied to the system. Because of the potential for GICs and the associated transformer reactive power losses to increase over a period of several dozen seconds, transient stability analysis is being considered. In this approach the GICs and associated transformer reactive currents are calculated at each time step during the transient stability solution. Preliminary results indicate that more detailed dynamic simulations need be considered when doing GMD vulnerability assessments. Power flow results, even with constant PQ load models, could substantially under estimate the risk.

VI. Conclusions and Future Work

This paper has presented results on moving power system GMD assessment into tools useable by power engineers. The paper has presented a methodology for including GMD assessment in the power flow and transient stability tools, and addressed issues of how existing power flow cases can be used for this analysis. Also, a computationally efficient algorithm for determining the set of transmission lines that contribute most to the effective GICs in a specified set of transformers has been presented. The paper has also introduced dynamic considerations for this analysis.

While much has been done, there are certainly issues that still need to be addressed. First, this paper has not considered the dependence of the results on the size of the system model itself. That is, the size of the **G** matrix. From a computational perspective this isn't a significant limitation since the matrix can be quickly factored even for large systems such as the EI. However, obtaining the GIC specific parameters needed to construct **G**, such as the substation grounding resistance, can sometimes be difficult. Default parameters can be used if necessary, but quantification of the associated error is an area for future research.

Second, this paper has not addressed the issue of how large of a study footprint is needed for voltage stability assessment. As mentioned in the introduction (from [6]), there are two primary risks to the bulk grid from GICs: damage to transformers due to increased heating and loss of reactive support leading to voltage collapse. Just knowing the transformer GICs can be helpful with the first, but to determine the impact of the GICs on the second requires power flow studies. The set of transformers for which the reactive power losses need to be calculated has not been addressed in this paper. This is an area for future study, undoubtedly building upon the rich voltage stability literature. Last, more work is needed to consider the short term voltage stability aspects, with a focus on appropriate transient stability timeframe models.

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Communication Architecture for Wide-Area Control and Protection of the Smart Grid (2.1)

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***Abstract*—The rapid increase of phasor measurements on the high voltage power system has opened opportunities for new applications to enhance the operation of the grid. To take advantage of high sampling rate of these measurement data, these applications will require a new information architecture that includes a high band-width, networked communication system connecting computers that can handle geographically distributed data and applications. The specifications for this next generation architecture that will overlay the continental power grids are under intense discussion at this time by organizations such as North-American synchro-phasor initiative (NASPI). In this paper we present a conceptual architecture for such a smart grid and a method to simulate, design and test the adequacy of the architecture for a particular transmission grid. The main difference from typical communication system studies is that we formulate the communication requirements from the power grid application requirements, that is, the design, simulation and testing is from the viewpoint of the anticipated power applications.**

I. Introduction

As the grid is operated closer to the margins it becomes imperative to collect fast sub-second measurements to gain insights about the dynamic behavior of the grid and to take necessary control actions for reliable operation of the system [1]. With the availability of phasor measurement units (PMUs), synchronized measurement of voltage and current phasors can be taken at rates of about 30 to 120 samples per second. Smart grid applications are designed to exploit these high throughput real-time measurements. Most of these applications have a strict latency requirement in the range of 100 milliseconds to 5 seconds [2-3]. To feed these new applications a fast communication infrastructure is needed which can handle a huge amount of data movement and can provide near real-time data delivery. In such a scenario it is evident that after a certain point, the notion of centralized operation and control will no longer be scalable. In the place of traditional one directional point to point communication links, the communication infrastructure needs to be upgraded to network of communicating nodes supported by a flexible middleware with high bandwidth and application specific quality of service (QoS) capabilities. Moreover, with the advances made in ubiquitous computing systems, the notion of distributed data and distributed analytics becomes amenable. The question then becomes - what should be the design of the new communications architecture? Given that the data and computations are going to be distributed, what data should reside where? How data is to be moved to the applications efficiently meeting the latency requirements? This paper attempts to answer these questions by presenting a possible design of communications architecture for wide area control and protection of the smart grid.

The rest of the paper is organized as follows: Section II lists the architectural considerations from the perspective of applications needed to be supported. Section III then describes the communications architecture. Section IV then presents a method to determine the bandwidth and latency requirements for a particular power system in consideration. Section V presents an approach to study the effects of latency on the design of a wide area damping control scheme. Section VI concludes the paper.

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II. Architectural Considerations

We begin by identifying broadly, the kinds of applications and their data requirements. A survey on some of the major applications in terms of their data requirements and latency was presented in [4] and reproduced in Table I for reference. A communication network designed to handle these applications will in principle be able to handle other derived applications as well.

A. Location of Data

In order to minimize the data traffic on the communication network, the choice of data that is put on the network will have to be determined by the application which will consume that data. Although the PMUs can sample the phasors at a rate of 30 to 120 samples per second, every application may not require data at such high rates. Hence each substation stores the data measured at that location in a local database and makes this data available. The approach here is to keep the data distributed and close to the power network components from which the data is measured.

B. Location of Applications

It can be observed from the latency requirements listed in Table 1, that only the class of applications concerned with transient stability of the system need faster data with higher detail. Other applications are relatively less stringent in the need for real time data.

TABLE I
SURVEY OF SMART GRID APPLICATIONS BASED ON LATENCY AND DATA REQUIREMENTS

Main Application	Applications based on it	Origin of Data/Place where we need the data	Data	Latency requirement	Number of PMUs we may need to optimally run the application	Data time window
Transient Stability	Load trip, Generation trip, Islanding	Generating substations/ Application servers	Generator internal angle, df/dt, f	100 milliseconds	Number of generation buses (1/20 buses)	10-50 cycles
State Estimation	Contingency analysis, Power flow, AGC, AVC, Energy markets, Dynamic/ Voltage security assessment	All substations/ Control center	P,Q, V, theta, I	1 second	Number of buses in the system	Instant
Small Signal Stability	Modes, Modes shape, Damping, Online update of PSS, Decreasing tie-line flows	Some key locations/ Application server	V phasor	1 second	1/10 buses	Minutes
Voltage Stability	Capacitor switching, Load shedding, Islanding	Some key location/ Application server	V phasor	1-5 seconds	1/10 buses	Minutes
Postmortem analysis	Model validation, Engineering settings for future	All PMU and DFR data/ Historian. This data base can be distributed to avoid network congestion	All measurements	NA	Number of buses in the system	Instant and Event files from DFRs

Thus, applications performing the transient stability monitoring and associated control actions can be decoupled from the control centers and be distributed across the grid closer to the substations which would be controlled. Such an arrangement will greatly reduce the burden on the communication network. The approach here is to move the applications to the data, instead of moving the data to the applications. In some cases the application may require both local data and the wide area data. For example, a state estimator needs both the changes in the local variables and also the topology of the entire system. In such cases, the state estimator has to be equipped with means to receive topology information from control centers. Alternately distributed two level state estimators [5] can be designed to run locally within the substation to estimate the state.

C. Movement of Data

Since the data and applications are defined to be distributed a communication infrastructure is needed which can identify a specific subset of data and transfer to the required application. The characteristics of such an infrastructure are described in [6]. A middleware system forms the heart of such an infrastructure, which can perform the functions of efficient routing of data packets while conforming to the quality of service (QoS) constraints. Design of such a middleware is one of the goals of NASPI [2-3] and initiatives such as GridStat [7-8]. An architectural paradigm known as publish/subscribe is suitable for such a middleware. The sources of data need not be aware of the consumer of data. The sources simply *publish* their data to the middleware. The applications which require specific data will *subscribe* to the middleware. A list of all received subscriptions is maintained by the middleware. As and when the data is published the middleware *notifies* the receiving application and forwards the data.

D. Format for Data and Control Commands

The PMUs are being manufactured by multiple vendors and interoperability among equipment from different vendors is ensured by using standard formats. The standard C37.118 is used in practice for communication of PMU data [9]. Among the four frames that are defined in C37.118, the data frame is one that is sent out from the substation under normal conditions. The command frame defined in C37.118 can be used to send commands to the PMUs for controlling the associated power system equipment.

E. Management of the Middleware

While the system becomes increasingly distributed an effective means of configuring the flows on the communication infrastructure is needed. In order to achieve this the middleware should provide an interface which can be used to manage and configure the subscriptions from various applications. One of the major responsibilities of the middleware is to deliver the QoS requirements. These functions are achieved by middleware by separating the data plane and management plane. As an example, the functionality of GridStat [7] is shown in Fig. 1.

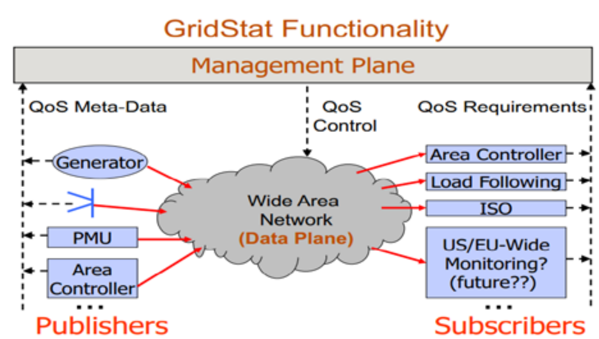

Fig. 1. Basic Middleware Functionality of GridStat

III. DISTRIBUTED COMMUNICATION ARCHITECTURE

Based on the considerations discussed in Section II we can infer that some of the applications needing lower latency can be decentralized. As a consequence of this decentralized or distributed approach a need arises for storing the data at various levels. Since, only a subset of data is communicated as per the requirement of the applications, effective data management strategies are needed to define the movement of the data across the various nodes of the network. To address this need, an information architecture for power system operation based on distributed controls using a publish/subscribe communication scheme and distributed databases is described in Fig. 2.

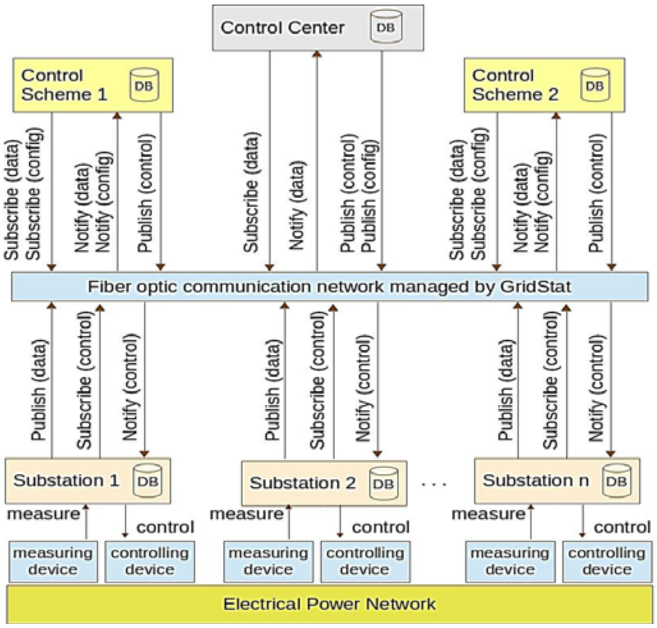

Fig. 2. Distributed communications architecture for power system control

The key feature of the proposed architecture is that the databases are distributed at each level. Each substation stores the measured data locally. Applications that need real-time data for transient stability monitoring and control are not located in the control center but can be located on a computing node near the substations, identified as "control schemes" in Fig. 2. The special protection schemes (SPS) being used in power systems are one example for such control schemes. At this level the data can also be stored for future use in computations. The data and control frames, as described by the C37.118 standard, can be exchanged via publish/subscribe based middleware which manages the fiber optic communication network. The communication network can be physically laid along with the power system network. The control center has its own set of applications and associated databases. While the focus is on optimizing the latency of time critical data, the data which is non-time critical can also be moved around with appropriate QoS attributes using the same communication network. The objective is to achieve a configuration of communication network which is most efficient and compatible with the operation of power system network in a decentralized way.

IV. Method to Calculate the Bandwidth and Latency Requirements

A. Choice of Protocol Stack

We define data latency as the time between when the state occurred and when it was acted upon by an application. Among the other delays [10], communication delay also adds to the latency and needs to be minimized. The communication delays on the network are comprised of transmission delays, propagation delays, processing delays, and queuing delays [1]. Each of these delays must be looked into to understand the complete behavior of the communication network for a given network. PMUs are constantly sending out the data frame on the network. Considering this, user datagram protocol (UDP) becomes a preferred protocol at the transportation level over transportation control protocol (TCP). At the application layer, constant bit rate (CBR) is a good choice to carry the continuously generated data frames of PMU. Maximum transmission unit (MTU) size of the link layer will play an important role as OpenPDC is designed to receive a complete C37.118 packet and not a broken one. As shown in the simulations, packet size can be around 1500 bytes, i.e. Ethernet communication having MTU size as 1500 bytes is the obvious choice. Given the latency and bandwidth requirements, optical fibers and broadband over power line (BPL) are the promising solutions. For uniformity we assume that optical fiber is present throughout the network. Hence the protocol stack will look like as shown in Table II.

TABLE II
PROTOCOL LAYERS FOR COMMUNICATION IN ONE CONTROL AREA

Layer	**Protocol**
Application	CBR
Transportation	UDP
Network	IP
Data	Ethernet
Link	Ethernet (Optical fiber)

With the above specifications, one of the possible communication scenarios was simulated using an event based, open source communication network simulator called NS2 version 2.34 [12, 13]. Further supporting codes were written in Matlab, Python, Tcl and Awk scripts to do the analysis. Two systems were studied as shown in section IV B and IV C. In this paper a brief summary of the results are presented. The detailed description of the simulation, design considerations, assumptions, and complete results are described in [4].

B. Simulation Results for WECC 225 Bus System

The WECC 225 bus is a reduced model of the WECC transmission network representing almost same geographical area. Table III, shows the WECC system statistics. Network topologies considered have minimum spanning tree, or 1, 3, or 5 links from control center to substations. Six basic traffic types are considered as follows.

1. All the Substation (S/S) to Control Center (CC)
2. Control Center to Control Substation (Generating stations and substation having control units like transformers and reactors)
3. Control Scheme (CS) substation to CS
4. CS to CS substation
5. Generating substation to Generating substation
6. CSs to Control Center

TABLE III
WECC STATISTICS AFTER NODE REDUCTION

S.No.	**Parameter**	**Value**
1	*Buses*	225
2	*Substations*	161
3	*Control Center*	1
4	*Control Scheme (CS)*	16
5	*Generating S/S*	31
6	*Control S/S*	58
7	*CS S/S*	160

The simulation was carried out for four different topologies, with increasing number of links between control center and substations as indicated by the rows of Table IV. It is observed that bandwidth usage decreases as more links are added. Similarly, as shown in Table V the delays in communication also decrease as more links are added. Thus, using the method described here one can estimate the communication delays. The simulation also shows that the communication network is able to satisfy the latency requirement of transient stability studies which is set as 100 milliseconds.

TABLE IV
LINK BANDWIDTH USAGE FOR WECC SYSTEM

Topol-ogy	Max. of used links (Mbps)	Min. of used links (Mbps)	Average of used links (Mbps)	Median of used links (Mbps)	% of unused Gw2Gw links
Min S.T.	58.75	0.10	5.46	0.39	28.6%
1CC links	45.60	0.08	3.34	0.62	11.4%
3CC links	46.80	0.10	2.97	0.51	11.7%
5CC links	44.09	0.08	2.03	0.38	10.8%

TABLE V
MAXIMUM DELAYS FOR DIFFERENT TRAFFIC TYPES WECC SYSTEM

Network Topology	Type1 (ms)	Type2 (ms)	Type3 (ms)	Type4 (ms)	Type5 (ms)	Type6 (ms)
Min S.T.	49.9	40.3	45.1	46.3	44.0	40.3
1CC links	26.2	27.6	26.6	27.1	29.4	23.9
3CC links	19.2	19.1	25.2	25.5	29.3	16.4
5CC links	11.7	5.2	13.8	12.9	15.6	4.5

C. Simulation Results for Polish 2383 Bus System

Another simulation study is carried out on the Polish power system which is divided into 5 zones. The case data for this system is available in [11]. In this simulation only the inter control center communication is considered. Each zone has a control center and every control center is connected to every other control center with either one or more links. The zonal statistics of the Polish system are shown in Table VI. For this study the system power network data is exchanged between control centers and the corresponding delays are determined for different values of communication bandwidth as shown in Table VII.

TABLE VI
ZONAL STATISTICS OF THE POLISH SYSTEM

Parameter	Zone1	Zone2	Zone3	Zone4	Zone5
Substations	*343*	259	831	515	268
Control Center	1	1	1	1	1
Control Scheme	34	25	83	51	26
Generating S/S	42	36	88	92	47
CS S/S	56	51	104	112	63
CS / SS	340	250	830	510	260
CC links	*5*	5	7	7	5

TABLE VII
DELAY FOR INTER CONTROL CENTER COMMUNICATIONS

Bandwidth for CC to CC links (Mbps)	Delay in CC to CC communication	
	Maximum (ms)	Average (ms)
25	118.4	69.1
50	84.3	46.3
75	71.1	39.2
100	65.5	35.5

It can be observed that the bandwidth of 100 Mbps would limit the maximum latency to 65.5 milliseconds and average delay to 35.5 milliseconds. Thus in this section the communication delays are calculated for a given power system topology and communication network bandwidth.

V. EFFECT OF COMMUNICATION LATENCY ON DESIGN OF WIDE AREA DAMPING CONTROLLER

In this section we take one step further and study how the communication delays affect the dynamic stability of a system via the design of wide area damping controller (WADC) for a 4 machine 10 bus system [14]. Communication links can also be used to transport data over long distance to support close-loop control applications such as WADC. The controllers using remote signals have certain constraints on latency. The goal of this study is to test if existing network parameters can satisfy such constraints.

A. Communication Network Scenario

First, a communication scenario is generated based on topology information of a power system. Several assumptions are made about the long-distance model of fiber optic fibers, package size and protocol used on each layer. This scenario is then simulated in NS-3 under different values of bandwidth. We send 60 data package per second from nodes that represent a substation with PMU installed to the communication node at the control center. Information like data size, package ID, related time stamp for each package is recorded. We sort the sending and receiving time by the IP of its sending node and calculate the average time delay on certain communication links carrying the input data for the controller. In order to determine the stability of a power system after disturbance, the time delay calculated above is then applied to a Simulink model for the two-area, four-machine system. We can determine the stability by observing parameters such as rotor angles of generators. The single line diagram of the test system is shown in Fig. 3. Fig. 4 illustrates the topology of the communication network which consists of 8 nodes. The substations having multiple voltage levels are grouped under one single communication node and the node no. 8 represents the control center. The WADC is installed on generator at node 1. The controller at node 1 receives the remote signal from node 3 via the control center at node 8. However it should be noted that a major part of the time delay in data flow occurs during the communication between nodes 3 to 8, hence this is taken as the time delay for the controller. Considering that fiber-optic cables are used, we add a repeater every 10km in the network links to keep the strength of optical signal. Coordinates of all communication nodes including substations and repeaters are generated so that this scenario can be visualized in the animation tool provided by NS-3.

The last part of the scenario stores system settings like the bandwidth and the number of CBR connections. We assume that all data measured by different PMUs in the same substation will be sent through only one data package. Therefore, all PMUs in this substation are represented by a single communication node during simulation. The data flow between substations and the control center is much larger than the data flow of other types of communication.

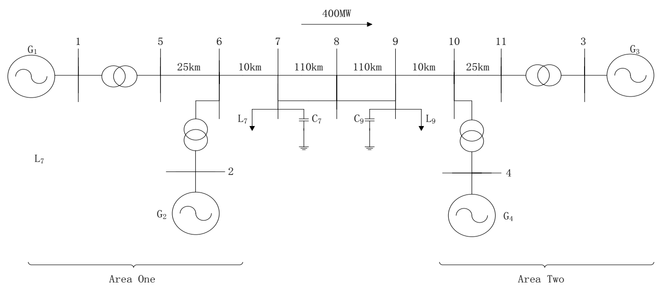

Fig. 3. Two-area four-machine power system

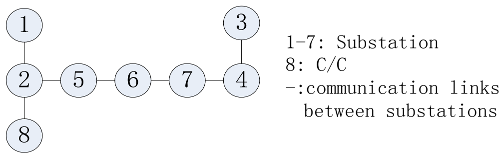

Fig. 4. Substation connection diagram

So only this kind of connection is simulated to calculate the time delay. Each PMU has 9 analog channels and 9 digital channels, and measures 6 phasors. The number of PMUs is calculated from the number of feeders attached to that substation. Based on header information from the C37.118 standard, the smallest size is about 440 bytes and the largest is about 544 bytes. The number of packets is assumed to be 60 per second.

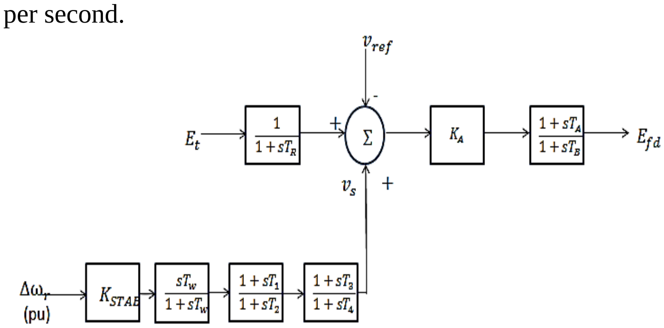

Fig. 5. Excitation system with PSS

B. Communication Network Simulation Results

Simulations are carried out with two different bandwidths, namely 10 Mbps and 3 Mbps. The average time delays are listed in Table VIII. It is observed that time delay from node 3 to node 8 is 79 milliseconds with 10 Mbps link as opposed to 210 milliseconds with 3 Mbps link.

TABLE VIII
NS-3 SIMULATION RESULTS

Bandwidth (Mbps)	Average Time delay (ms)	Time delay between nodes 3- 8 (ms)	Variance (s^2)
10	39	79	3.3E-32
3	132	210	1.36E-03

C. Modeling of WADC with Delay Using Matlab Simulink

Having determined the communication delays, the next step is to design a WADC for the above 4 machine system. The system shown in Fig. 3 consists of two fully symmetrical areas connected together by two 230 kV lines of 220 km length. Identical speed regulators are further assumed to be installed at all locations, in addition to fast static exciters with a 200 gain. The load is represented as constant impedances and split between the areas in such a way that area 1 is exporting 400MW to area 2. To damp the local mode, conventional PSS using Δω as an input (ω is the local generator speed) is installed on all plants, which structure is shown in Fig. 5.

WADC is added to the exciter at G1 as in Fig. 6. The input signal is the changing part of differential speed signal between the remote generator and the local generator ($\Delta(\omega_3 - \omega_1)$). The transfer function of the controller is calculated residues compensation [15]. The parameters are as follows:

$$H_{PSS}(s) = 30\frac{10s}{1+10s}\left(\frac{1+0.05s}{1+0.03S}\right)\left(\frac{1+3.0s}{1+5.4s}\right)$$

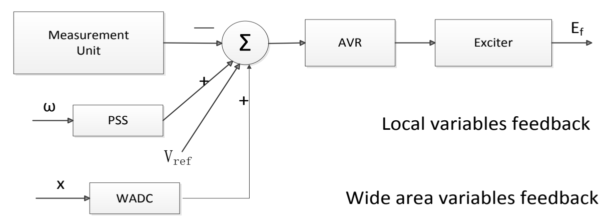

Fig. 6. Excitation system with WADC with remote signal

In the above figure a time delay as per the assumed bandwidth is introduced in the WADC input signal. To test the dynamic stability in this system, a 5%-magnitude pulse is used, applied at the voltage reference of the exciter at G1 for 12 cycles.

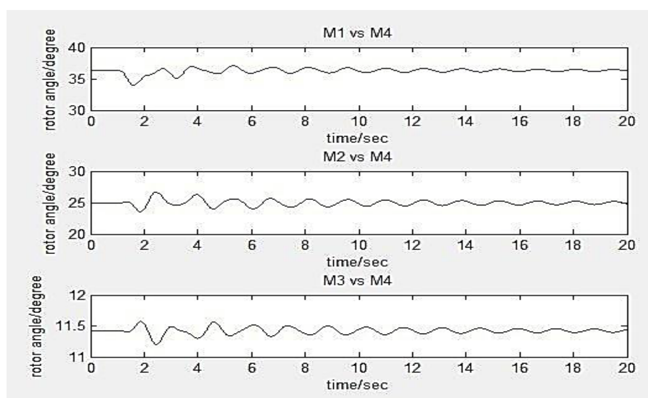

Fig. 7. System performance with 10 Mbps. The system is stable.

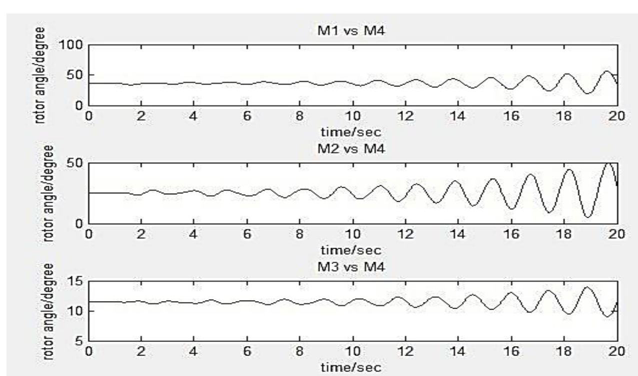

Fig. 8. System performance with 3 Mbps. The system is unstable.

F. WADC Simulation Results

During the simulation, the input of the damping controller is delayed by a certain time, calculated by the NS-3 results shown above. Relative rotor angles are plotted to determine the stability. The rotor angle of generator 4 (M4) is used as reference value. Fig. 7 shows the results with 10 Mbps bandwidth (a time delay of 79 milliseconds), whereas Fig. 8 shows the results with 3 Mbps (a time delay of 210 milliseconds).

From the results we can see the oscillation of rotor angles after the disturbance. With a bandwidth of 10 Mbps, this oscillation is damped out by WADC at the end of simulation. However in the 3Mbps case, that oscillation makes the whole system unstable. The amplitude of oscillation keeps growing with time. So we can say that if the network condition is not good enough, the time delay introduced by remote-data transport can completely change the stability of a power system.

VI. Conclusions

In this paper the evolving trend of wide area power system control towards distributed applications and databases is presented. As the size of the system grows and the PMU data becomes available with faster data rates, the centralized operation and control may no longer be scalable. To address this need, a distributed architecture for communication, computation and control is described.

The paper also outlined a process for simulating the performance of the communication network to determine the bandwidth and latency requirements. This is a system specific study based on certain design assumptions. However the simulation methodology is generic and useful for design of communication infrastructure. Propagation delay changes with network topology, whereas, queuing delay and transmission delays change with the communication bandwidth. Average link bandwidth needed for smart grid applications should be in range of 5-10 Mbps for communication within one control area and 25-75 Mbps for inter control center communications. Using meshed topology delays can be contained within the 100ms latency requirement satisfying all applications.

The effect of communication latency on the design of wide area controllers is also demonstrated with an example of a damping controller. It is observed that if adequate bandwidth is not used for acquiring remote signals for closed loop control, the delays in getting the signals increase and the performance of the controller deteriorates to an extent that the controller is no longer able to stabilize the system after a disturbance.

The architecture and the process described in this work aim towards development of a holistic approach for design of new decentralized and scalable architectures using distributed applications and distributed databases for wide area control of future smart grids.

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VIII. Biographies

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Improved Power Grid Resiliency through Interactive System Control (6.3)

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***Abstract*--With the increasing deployment of synchronized phasor measurement units (PMUs), more wide-area measurements will be available and controls based on these measured signals are likely to find broader implementation. To transmit wide-area signals, communication networks are required. However, communication systems are vulnerable to disruptions as a result of which the stability and reliability of power systems could be impaired. This research project addresses a critical issue related to engineering resilient cyber-physical systems. It provides two approaches to utilize wide-area measurements in control and also guarantee robustness of the control in the event of loss of communication of the measured wide-area signal. The approaches developed in this work could be used to establish controls resilient to communication failures in power systems. Additionally, this work is particularly important with regard to leveraging the large national investment in installing PMUs.**

I. Introduction

As the penetration of renewable resources and grid transactions increase, power systems are prone to the problem of low frequency oscillations, especially inter-area oscillations. Compared to a controller based on local signals, controllers using wide-area signals may be more effective in damping inter-area modes because wide-area measurements have more modal observability of area wide phenomenon compared to local measurements. In order to more effectively damp inter-area oscillations, wide-area based controllers have been proposed in earlier studies [1], [2] and [3]. The ability and the potential for the future grid to use wide-area signals for control purpose have greatly increased with the significant national investment in the U.S. in deploying synchrophasor measurement technology.

Fast and reliable communication systems are essential to enable the use of wide-area signals in controls. If wide-area signals find increased applicability in controls the security and reliability of power systems could be vulnerable to disruptions in communication systems. Even though numerous modern techniques have been developed to lower the probability of communication errors, communication networks cannot be designed to be always reliable.

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Therefore, the motivation of this work is to build resiliency in the power grid controls to counteract failures and time delays associated with the communication network. Although transmission delay has been considered in wide-area based control in previous studies such as [4] and [5], the problem of building appropriate control which is resilient to loss of wide-area measurements due to communication failures has not been explored yet. In this proposed work, two approaches; a passive and an active method, are presented to build resiliency in the physical system to counteract communication failures. The approach to the solution in both methods is motivated by considering the use of a robustly designed supplementary damping control (SDC) framework associated with a static VAr compensator (SVC). When there is no communication failure, the designed controller guarantees enhanced improvement in damping performance. When the wide-area signal in use is lost due to a communication failure, however, the resilient control provides the required damping of the inter-area oscillations by either utilizing another wide-area measurement through a healthy communication route or by simply utilizing an appropriate local control signal. With the proposed control included, the system is stabilized regardless of communication failures, and thus the reliability and sustainability of power systems is improved.

II. Approach/Methods

A. Study System

To illustrate the solution to the problem of formulating resilient controls, the IEEE 50-generator system [6] is utilized. Fig. 1 shows the one-line diagram of the system with two areas of interest. In this research work, the inter-area modes associated with the two areas are examined and SDCs are primarily designed to provide supplementary damping of the critical inter-area mode.

The network data of the IEEE 50-generator system can be found in [6] while the dynamic modeling of the system including generators, exciters and PSS is described in detail in [7]. Fig. 2 illustrates the SDC associated with the SVC. The SDC to be designed consists of the dashed box added to the SVC's voltage control loop. To guarantee that the SDC only works in the transient state and does not influence steady state voltage regulation, a washout filter is also included. Additionally, a limiter, with bounds set at V_{max} = 0.2 and V_{min} = -0.2, is imposed on the output of the SDC. The SVC is installed at bus #44 so that its output could strongly influence the relevant inter-area modes of oscillation [8].

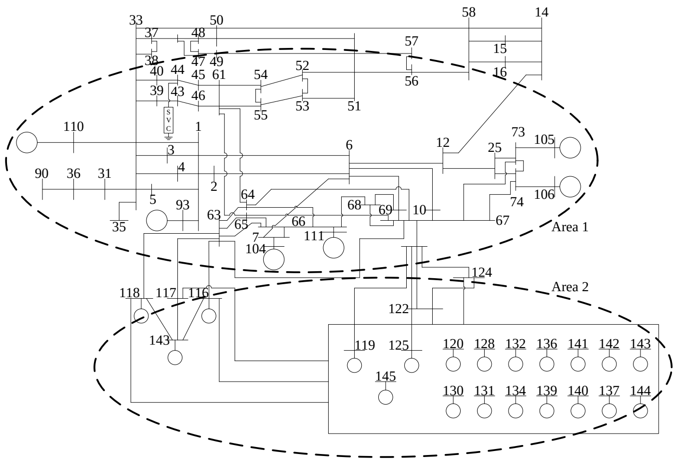

Fig. 1. One-line diagram of the IEEE 50-generator system

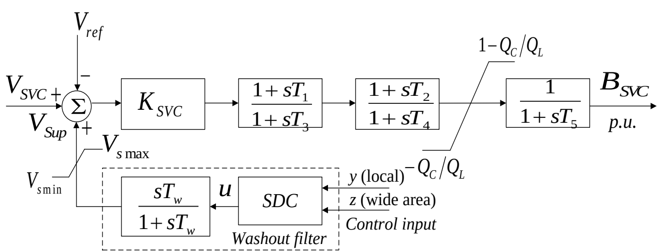

Fig. 2. SVC model with the SDC to be designed

The variation of the system operating conditions is characterized by the change of the active power output at bus #93 and #110 (G93 and G110). This generation is considered to be varied from 2×1300 MW to 2×1800 MW with a generation of 2×1700 MW regarded as the nominal operating scenario. The machine, exciter, power system stabilizer (PSS) and SVC models are linearized around the nominal operating condition in order to obtain the system matrix.

After conducting a complete eigenvalue analysis, two eigenvalues, shown in Table I, confirm the presence of two poorly damped inter-area modes of which the second mode is more critical since its damping ratio decreases as the generation at G93 and G110 increase. Hence, the supplementary damping is primarily provided to damp this mode.

TABLE I
TWO POORLY DAMPED INTER-AREA MODES OF THE OPEN-LOOP FIFTY-MACHINE SYSTEM

G93, G110 (MW)	Mode 1	Mode 2
2×1300	3.53% @ 0.482 Hz	9.13% @ 0.292 Hz
2×1350	3.57% @ 0.481 Hz	8.68% @ 0.289 Hz
2×1400	3.55% @ 0.481 Hz	8.10% @ 0.286 Hz
2×1450	3.53% @ 0.482 Hz	7.38% @ 0.283 Hz
2×1500	3.59% @ 0.480 Hz	6.47% @ 0.279 Hz
2×1600	3.65% @ 0.479 Hz	4.14% @ 0.273 Hz
2×1700	3.70% @ 0.479 Hz	1.16% @ 0.266 Hz
2×1800	3.77% @ 0.478 Hz	-3.00% @ 0.261 Hz

B. *Formulation of the Resilient Control Framework*

In order to make controls in the electric grid resilient to communication failures, it is a good idea to identify backup signals which are either wide-area or local and design a framework to incorporate these signals. In other words, when an input to the controller which happens to be a wide-area signal becomes unavailable due to a communication failure, the controller is supposed to retain its essential control capabilities by utilizing an alternative control signal. Two approaches to establish fault-tolerant control are proposed in this work.

1) Passive Fault Tolerant Control

In this method, the proposed control is designed to utilize both a wide-area signal, which serves as the primary control input, and a local signal, which is used as the backup input, simultaneously. The local measurement requires no remote transmission and thus it is an excellent alternative for the wide-area input in the event of communication loss. Although the damping effectiveness of a local input could be limited, it is necessary to guarantee the basic stabilizing control effect against the failures in the communication network. On the other hand, the wide-area signal is utilized as an additional control input because it provides better observability of the inter-area oscillations than the local signal. The improvement in system damping could be enhanced if both signals are included.

As illustrated in Fig. 3, two feedback loops are formed to stabilize the system. In these two loops, the wide-area signal and local signal are used as the feedback respectively. For the inner loop, a single-input single-output (SISO) H_∞ optimal controller K_2 is obtained first to guarantee the system is stabilized even if the wide-area measurement is lost. A second H_∞ optimal controller K_1 is then designed in the outer loop to further improve the damping of the augmented system with the inner loop included.

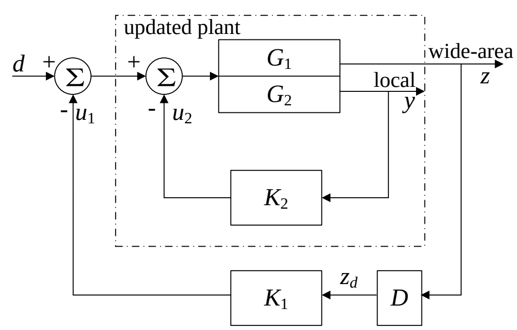

Fig. 3. Sequential H_∞ synthesis framework

The transmission delay is rationalized by using a second-order Padé approximation [9] as shown in (1) and taken into account in the design of the outer controller. The delay can be expressed as,

$$D = e^{-sT_d} \approx \frac{\frac{1}{12}T_d^2 s^2 - \frac{1}{2}T_d s + 1}{\frac{1}{12}T_d^2 s^2 + \frac{1}{2}T_d s + 1} \tag{1}$$

The proposed resilient control actually consists of two SISO controllers which can be acquired via sequential H_∞ synthesis. The failure of the outer control loop due to the loss of wide-area measurement does not influence the control effectiveness of the inner loop. The control framework automatically reduces to a SISO controller using only the local signal when it suffers an external failure in the communication link. The word "passive" in classifying this controller indicates that this type of control does not require any action to replace the input signal to retain its ability to provide sufficient damping after a communication failure occurs.

2) Active Fault-Tolerant Control

Different from the passive method, the active approach presents a control framework that requires real-time channel inspection and switching among a couple of pre-designed control laws [10]. To survive communication errors, this approach proposes setting up a hierarchical set of candidate signals which are transmitted via redundant communication channels independent from each other. If one of these channels suffers a communication failure, the control will switch to using another wide-area signal in the hierarchy through a healthy communication route instead of the faulty one.

The candidate signals for the control input are sorted in a descending order in terms of their observability factors and residues, as displayed in Table II.

TABLE II
RESIDUE AND OBSERVABILITY WITH RESPECT TO THE CRITICAL MODE AROUND 0.28 HZ

Candidate signal	Residue	Observability
$\Delta I_{63\text{-}66}$	-0.0064 + j0.0028	0.2706
$\Delta I_{61\text{-}63}$	-0.0054 + j0.0024	0.2517
$\Delta I_{1\text{-}6}$	-0.0041 + j0.0019	0.2101
$\Delta I_{2\text{-}6}$	-0.0040 + j0.0017	0.1976
$\Delta I_{43\text{-}46}$	-0.0025 + j0.0012	0.1451
$\Delta I_{44\text{-}45}$ (local)	-0.0023 + j0.0010	0.1340
$\Delta I_{40\text{-}44}$ (local)	-0.0023 + j0.0006	0.1329
$\Delta I_{33\text{-}40}$	-0.0022 + j0.0006	0.1310

With the set of hierarchical candidate signals identified, the resilient control framework that incorporates such a signal set can be established.

As shown in Fig. 4, this framework consists of multiple SISO controllers which provide supplementary damping to the system through the SVC. All these controllers are pre-designed either with transmission delay considered or not which depends on whether the corresponding input is a wide-area measurement or a local measurement. At any given time, only one of these controllers will be utilized to damp system oscillations. The sequence of using these damping controllers is determined by the hierarchy of their inputs as well as their control effectiveness. When the "first-ranked" signal in the hierarchy fails due to a communication failure, SDC #2 as well as the "second-ranked" signal instead of SDC #1 and the "first-ranked" signal would be used to perform the damping control, and then SDC #3 will replace SDC #2 when it fails, and so on. In this way, there is always a SDC in service to improve the system damping irrespective of communication failures.

Since switch among different channels and control laws is proposed in this scheme to implement the resilient control in response to communication failures, it is necessary for the control to determine when the channel should be switched. Apparently, such a problem is equivalent to real-time detection of the channel abnormalities.

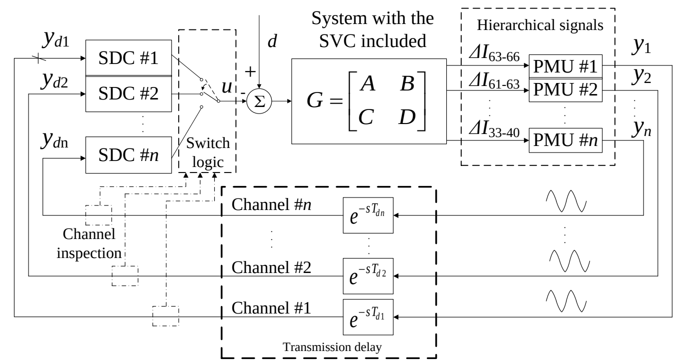

Fig. 4. Resilient control framework with hierarchical signals as the input

The principle of real-time channel fault inspection is graphically illustrated in Fig. 5. The comparison of the mathematical morphology (MM) of two independent signals is utilized to distinguish the failures in the communication system from those in the physical system. Mathematical morphology is an excellent signal singularity analysis tool which has been widely used in image processing, machine vision and signal processing [11]. Discussions about the application of MM in power systems have also given in some previous efforts such as [12] and [13]. With a carefully selected structuring element which works like a signal filter, the point where the signal's change rate is discontinuous can be identified. Since both failures in the physical system and the cyber system could lead to discontinuity in the change rate of the signal, it is difficult to recognize the moment when the communication failure occurs through an inspection of a single signal. By comparing the MM transformation of signals in any two independent channels, however, it is possible to locate the communication error time with accuracy.

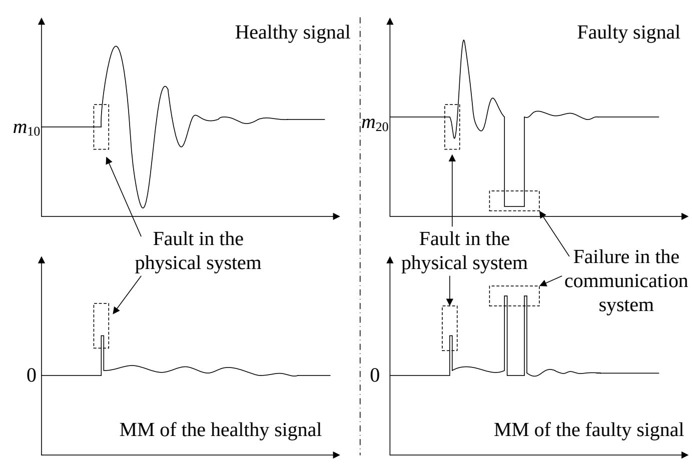

Fig. 5. Schematic explanation of the channel fault inspection

As Fig. 5 shows, if a fault occurs in the physical system, all measurements from the plant would "experience" such a fault and exhibit a sudden change in their waveform. Therefore, a significant value in the MM transformation of these signals would appear simultaneously. If a fault occurs in one communication channel in the cyber system, then only the MM transformation of the faulty signal would have a significant value. Based on such a characteristic, the approach to discern communication failures can be acquired: a threshold is first set to screen out all the significant values which indicate a physical system fault or communication fault occurs, then the communication fault is identified if the signal's MM value in the corresponding channel is uniquely significant compared to signals in other channels at a time.

In order to avoid erroneous identification due to occasional simultaneous failures in two independent communication channels, the channel inspection is designed to consist of multiple comparisons.

III. Results

In order to verify the effectiveness of the two resilient control frameworks proposed in this work, small signal stability analyses are first performed using the SSAT program [14]. In addition to the eigenvalue analyses, nonlinear time domain simulations are also conducted using the TSAT program [15]. A three-phase fault is applied to bus #1, which is close to both generator #93 and #110, for six cycles (0.1 s) and then removed. Three variables, including rotor angle of generator #93, current magnitude on tie-line 63-66 and active power output of generator #139, are monitored to show the damping effect of the controller in the normal communication case as well as the communication failure case. To evaluate the impact of the transmission delay, different values of T_d are also considered in the simulations. The results are given in the sub-sections corresponding to the two different proposed approaches.

A. Test of the Passive Method

A comparison of the damping ratio with respect to the critical model among different cases is given in Table IV.

TABLE IV
Comparison of Damping Ratio of the Critical Mode

G93 & G110 (MW)	Without SDC	SDC (loss of communication)	SDC (normal communication)
2×1300	9.13%@0.292 Hz	11.00%@0.296 Hz	13.23%@0.313Hz
2×1400	8.10%@0.286 Hz	10.65%@0.289 Hz	12.15%@0.309Hz
2×1500	6.47%@0.279 Hz	9.78%@0.280 Hz	11.34%@0.302Hz
2×1600	4.14%@0.273 Hz	7.99%@0.271 Hz	10.48%@0.294Hz
2×1700	1.16%@0.266 Hz	4.95%@0.262 Hz	9.57%@0.282Hz
2×1800	-3.00%@0.261 Hz	0.12%@0.254 Hz	8.24%@0.253Hz

Due to limited space, the dynamic responses of two monitored variables, rotor angle of the generator #93 (G93) and active power of generator #139 (G139) in the cases when T_d = 0.1 s and T_d = 0.7 s, are depicted in Fig. 6 – 9. The outputs of the two controllers are also shown in Fig. 10.

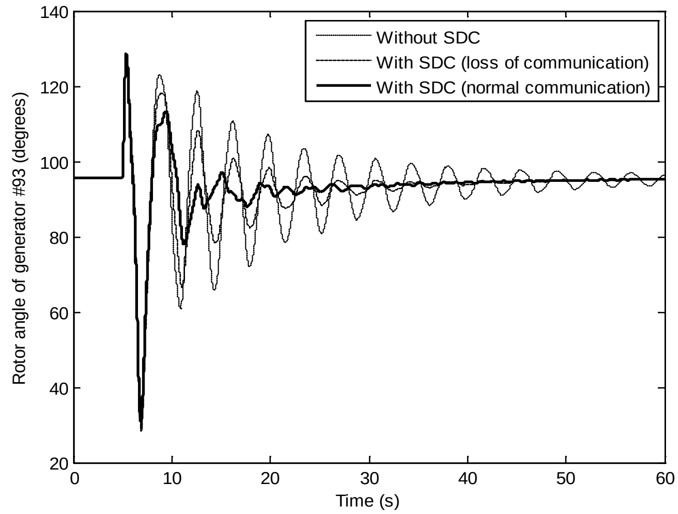

Fig. 6. Rotor angle of G93 with a transmission delay of 0.1 s (1700 MW)

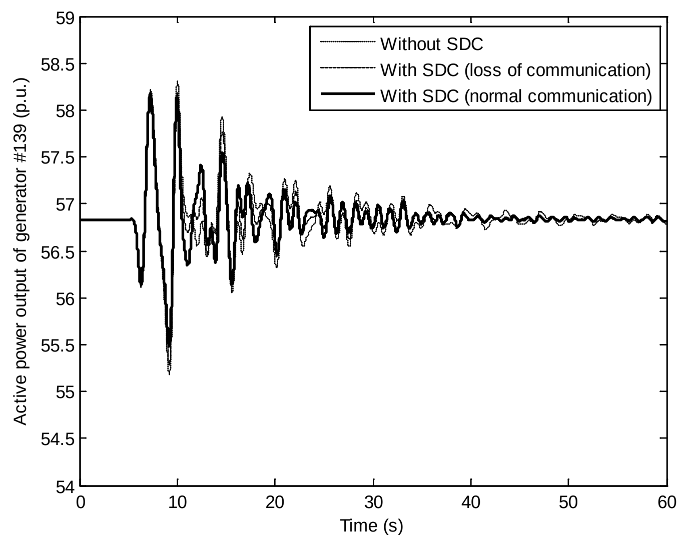

Fig. 7. P_{G139} with a transmission delay of 0.1 s (2x1700 MW)

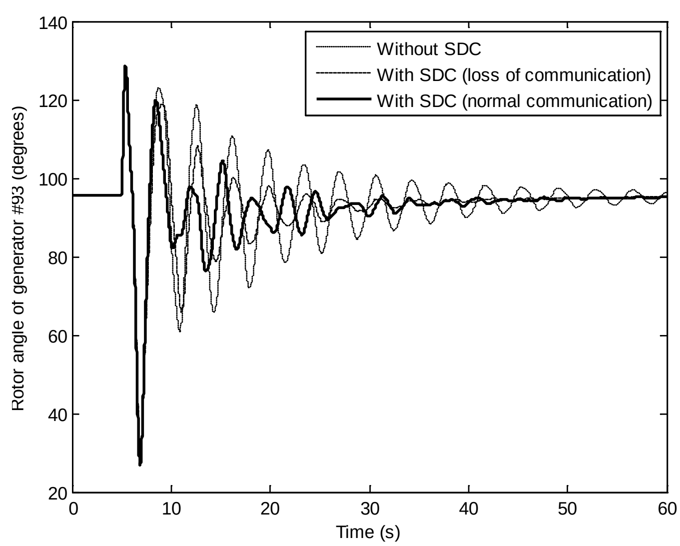

Fig. 8. Rotor angle of G93 with a transmission delay of 0.7 s (2x1700 MW)

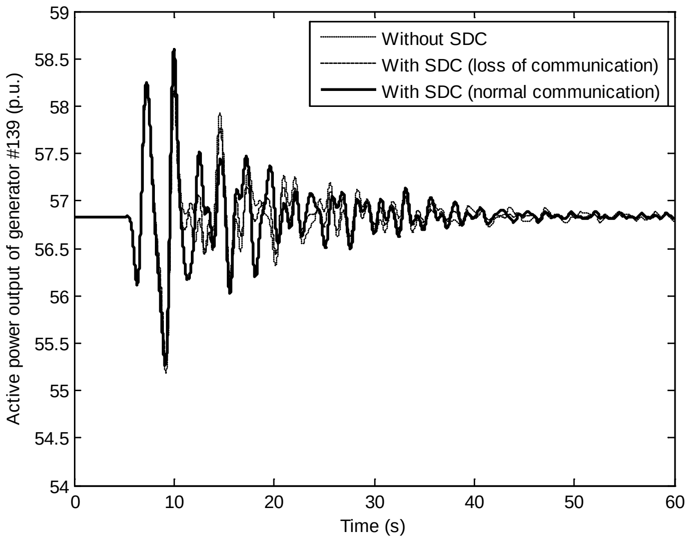

Fig. 9. P_{G139} with a transmission delay of 0.7 s (2x1700 MW)

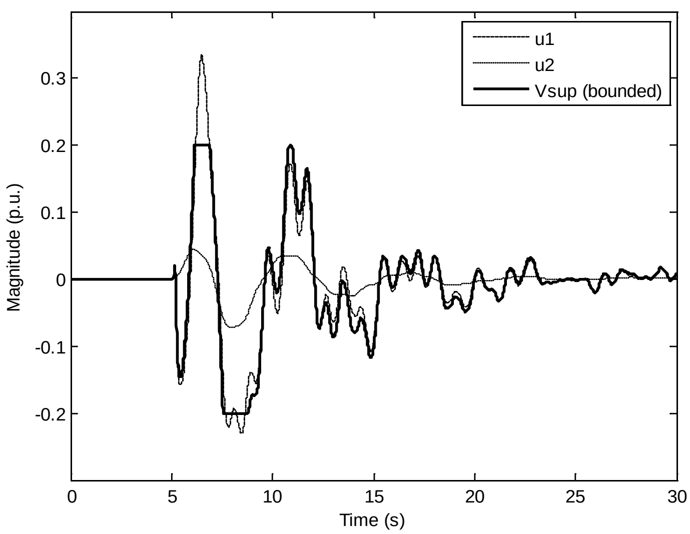

Fig. 10. Controller output with a transmission delay of 0.7 s

It can be observed from Fig. 6 - 9 that the controller provides a satisfactory damping performance when there is no failure in the communication channel of the cyber system. When the controller suffers a communication failure, however, the local signal based controller still stabilizes the system effectively. Another observed phenomenon is the damping effectiveness of the control with both wide-area and local measurement used becomes weak when the transmission delay is up to 0.7 s. This could be explained by Fig. 10 which reveals that the output of the controller with the local signal as the input is dominated by the output of the controller that uses the wide-area signal, while the wide-area signal is vulnerable to the transmission delay. Communication delays however, are typically less than such a significant value in most practical cases.

B. Test of the Active Method

Similarly, a comparison of the damping ratio for the critical mode around 0.28 Hz can be made between the open loop system and closed loop systems with different control signals. A portion of the results is shown in Table III.

TABLE III
COMPARISON OF DAMPING RATIO OF THE CRITICAL MODE

G93, G110 (MW)	Open loop	Closed loop		
		z: $\Delta I_{63\text{-}66}$	z: $\Delta I_{61\text{-}63}$	z: $\Delta I_{1\text{-}6}$
2×1300	9.13% @0.292 Hz	12.27% @0.306 Hz	12.11% @0.306 Hz	11.86% @0.306 Hz
2×1400	8.10% @0.286 Hz	11.48% @0.305 Hz	11.20% @0.306 Hz	10.73% @0.305 Hz
2×1500	6.47% @0.279 Hz	10.61% @0.305 Hz	10.38% @0.305 Hz	10.01% @0.304 Hz
2×1600	4.14% @0.273 Hz	9.96% @0.303 Hz	9.54% @0.302 Hz	8.26% @0.301 Hz
2×1700	1.16% @0.266 Hz	8.85% @0.299 Hz	8.62% @0.297 Hz	5.12% @0.297 Hz
2×1800	-3.00% @0.261 Hz	6.69% @0.296 Hz	6.67% @0.294 Hz	4.98% @0.294 Hz

Sample time domain simulation results are provided in Fig. 11 and Fig. 12.

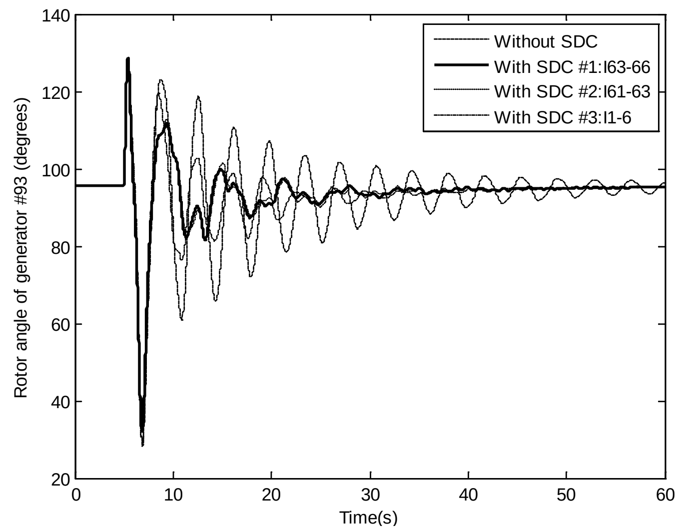

Fig. 11. Rotor angle of G93 with a transmission delay of 0.1 s (2x1700 MW)

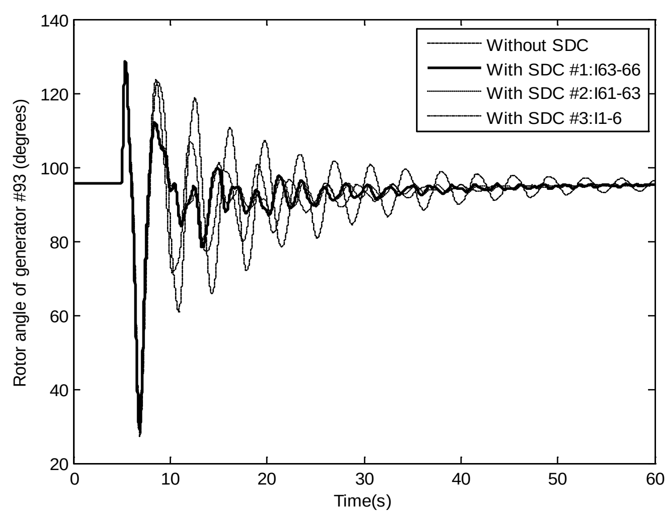

Fig. 12. Rotor angle of G93 with a transmission delay of 0.7 s (2x1700 MW)

Similar to the results obtained in the test of the passive method, the observed results in this part also indicate that the proposed control can not only improve the small signal stability performance but also the transient stability performance of the system. Once the signal in use which happens to be a wide-area signal fails, the control strategy automatically adopts another healthy signal (either local or wide-area) in the hierarchy to continue stabilizing the system. With such a framework, the grid control resiliency is improved in case of unexpected communication failures.

IV. Conclusions

This work proposes two approaches to build resilient control in response to communication failures. The simulation results have demonstrated that controls presented in both approaches provide supplementary damping to the system irrespective of whether the system suffers a communication failure or not and thus improve the stability performance and control resiliency of the system. For the first proposed method, the control is designed to automatically adapt to the number of its input without channel inspection. Hence this kind of control is free of stochastic errors and time delay associated with the control switch. For the second method, channel inspection enables that the correct control input is used. As a result, the risk of deteriorated control effect because of unexpected transmission errors could be accordingly reduced. In addition, a large set of wide-area measurements are used as a backup for the faulty signal, so it is very likely that a healthy signal through an alternate communication route to replace the original one can be found. Therefore, the control which adopts the new input is able to adequately damp the system oscillations. In conclusion, with either of the two proposed resilient controls adopted, the damping control is going to be much more reliable and system stability is guaranteed.

V. Future Work

So far, the work of building resiliency in grid controls in response to communication failures has been only demonstrated on the example of supplementary damping control. In the future, this work would be extended to other applications in power systems such as generator valve control and load shedding. Moreover, the impact of data packet error due to communication failures will be studied and controls that are resilient to this kind of error will be developed by means of advanced control theory and mathematical tools.

VI. Access to Products

The products of this work including codes, algorithms and self-defined module will be available on the author's personal website (http://www.public.asu.edu/~szhang86). Passcode may be acquired via email to get access to these products. Relevant publications can be found in the IEEE Xplore database.

VII. Acknowledgment

The authors would like to convey their grateful thanks to Dr. Jeff Bloemink from Powertech Labs Inc. for his help in building the self-defined dynamic model in TSAT.

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IX. Biographies

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Wide-Area Control Systems (1.4)

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Abstract—**Recent advances in wide-area monitoring, communication and computational technologies have paved the way for development of sophisticated wide-area control systems for the large-scale power system. Advanced control designs are needed for ensuring operational reliability of the future power grid faced with complexity of high percentage of renewable power generation. Novel control designs are proposed in this project for addressing transient stability phenomena in power grids using synchronized wide-area measurements. Model prediction based wide-area transient stability control is designed wherein specific control choices are decided by evaluating the effectiveness of different actions in real-time and by monitoring the closed-loop wide-area system response. Methods for detecting subsynchronous oscillations introduced by incorrect power electronic control settings at wind farms are also discussed briefly.**

I. Introduction

Large-scale implementations of synchrophasors in North American power system are paving the way for introduction of novel wide-area control systems. We need to rethink all of traditional controls such as Automatic Generation Control (AGC) and Special Integrity Protection Schemes (SIPS) or Remedial Action Schemes (RAS) to bring them up to speed with emerging technology such as near real-time wide-area dynamic state estimation and so that they can handle unpredictable complex dynamic responses of large penetrations of renewable power sources in the future power systems. We need new control paradigms on how next generation wide-area controls can be designed by utilizing wide-area real-time synchrophasor measurements that will be communicating with each other in fast communication architectures. In the uncertain operating environments of the future with rapidly changing power-flows and with large numbers of diverse power electronic equipment, the complexity of operational reliability problems will force us to design wide-area controls that are designed and implemented in real-time for power system conditions at that time.

Our recent papers [1],[2] address the formulation of such controls as well as specific control strategies for mitigating angle stability issues in the new framework. The integrity of the system, in the context of this approach, is equated with a stable disturbance response, and acceptable performance limits are equated with important signals (e.g., voltage magnitudes and frequency) remaining within acceptable ranges. This paper summarizes the results of [1],[2] in the context of wide-area transient stability controller.

This paper investigates an angle stability control scheme utilizing feedback control to drive the system response according to an optimality principle, while adapting to the instantaneous system state at the time of a given disturbance. The result adapts to unforeseen contingencies and, due to its feedback nature, is tolerant of modeling inaccuracies. Feedback based wide area stability controls have been recognized as advancements over preplanned systems [3].

The power system is inherently nonlinear and the best control approach anticipates this nonlinear characteristic. Model predictive control (MPC) is a method of control action selection by using the current system state to solve a finite horizon open-loop optimal control problem [4]. MPC is well suited for nonlinear multivariable systems, typical of electric power systems. It does, however, require an estimate of the initial system state and model at each iteration instance. It also places high computational demands for real-time operation. While the preplanned system is constrained in the number of contingencies it can consider, it has the advantage of considering those cases offline. The approach considered here makes less assumptions about the possible contingencies, but must handle them online. This trade-off has historically tilted in favor of preplanned systems. However, many recent advances are removing these barriers to a real-time MPC inspired approach. For example, time-synchronized phasor systems now allow direct measurement of the power system network state and a fast linear instead of iterative nonlinear state estimator [5]. Also, direct synchronous machine rotor angle measurement systems, also time-aligned, have been proposed [6] and put into service [7]. Advances in computing power enable faster than real-time simulations and power system models continuously mature.

Model predictive control has been applied for voltage stability [8]-[10]. Systems applied for voltage stability can sample relatively slowly, compared to the prediction horizon. This shortens the time-domain aspect of the optimization problem and allows a broad control strategy search.

Work in the area of transient stability prediction with control includes a predictive scheme applied to a single-machine infinite bus (SMIB) model, with classical machine dynamics [11]. The control actuation was though adjusting a series capacitor value. An emergency hybrid transient stability method, "E-SIME" [12] [13], predicts and controls transient stability behavior by transforming the system into an approximate equivalent system. A fast integration technique

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for use in applying time-synchronized measurements to real-time DAE prediction for transient stability has also been developed [14]. Multiple angle instability detection algorithms using wide-area synchrophasors are proposed in [15]. For rotor-angle stability, [16] describes a system optimizing generator voltage deviation, mechanical-electrical torque mismatch, and speed increments. The following work continues this existing research, formulating the problem as a combination of stability prediction with state trajectory optimization, and expanding to higher order machine models. It is shown with a simple two-area system, capable of stabilizing difficult contingencies which otherwise lead to instability.

II. Model Based Predictive Control

The problem formulation involves three aspects. First, the system model, including state q, control inputs u, and topology s is selected.

$$\dot{q} = f(q, u, s) \tag{1}$$

A common power system model simplification takes advantage of its multiple timescale response. The state vector q is partitioned into component and network states. Component examples include induction machines, synchronous generators, power electronically controlled sources, and reactive power devices. The network states, complex valued voltages and currents, are approximated as responding instantaneously compared to the component states. They serve as algebraic constraint on the system component differential equations. Equation (2) shows how the resulting differential algebraic equation (DAE) system model consists of component (x) and network (y) subsets.

$$\begin{aligned} \dot{x} &= f(x, y, u, s) \\ 0 &= g(x, y, u, s) \end{aligned} \tag{2}$$

The size of x, defined as M, depends on the number of components and the order of their individual models. The size of y is equal to the number of buses in the system, N. Estimation of initial x and y is treated later. The size of u is equal to the number of available control options. The topology for a power system includes, in part, the matrix of network impedances, Y_{bus}.

Second, an objective function is used to minimize the difference between the reference system trajectory and the predicted trajectory along with the cost of the control.

$$min\{F(x, y, u, s)\} \tag{3}$$

Finally, constraints are imposed along the predicted trajectory.

$$h(x, y, u, s) < 0 \tag{4}$$

The specific form of the objective function, for a linear system, is provided in (5). The minimization solution drives control selection. In (5) the first term measures deviation of state from the desired state, the second term provides a means to prioritize control actions, and the third term minimizes sequential changes in control actions. The matrices Q, R, and S scale the costs. They are time-invariant, symmetric, positive definite.

$$\min_{u_{k+1,\dots,k+K}} \left\{ \sum_{i=k+1}^{k+K'} \begin{matrix} (q_i - q_o)^T Q (q_i - q_o) + \\ (u_i - u_o)^T R (u_i - u_o) + \\ (u_i - u_{i-1})^T S (u_i - u_{i-1}) \end{matrix} \right\} \tag{5}$$

During control selection iteration, a sequence of states q are predicted, with (2). The parameter K' in (5) is the prediction horizon. The parameter K is the control horizon, with K' ≥ K. After time K no further control is considered but the optimization continues to look ahead until time K' when selecting between possible control actions during the interval up to K. The control sequence which minimizes the objective, while meeting the constraints is selected. From that sequence, only the first control is applied. Then, the entire optimization is repeated at the next iteration.

III. Transient Stability Control

Electric power systems respond in a nonlinear manner, especially during large transients, and this inspires application specific changes to (5). The reference trajectory, q_o, consists of both network and component subsets. For the network a derived quantity such as power flow is often of interest. Meanwhile, for rotor angle stability the component models the relevant states are the machine rotor angles, referenced to the center of inertia angle. Equation (6) is a center of inertia angle [18] where the summation is over all of the generators in the system.

$$\delta_{COI} = \frac{\sum_{i=0}^{M-1} H_i \theta_i}{\sum_{i=0}^{M-1} H_i} \tag{6}$$

For the cost of control actions, because of the nonlinear nature of the problem, it is difficult to normalize the control terms such they contribute in a regular manner to the total cost for the various contingencies. Therefore, the objective function cost of the control is taken as a scalar multiplier to the state deviation cost. The reference control action is no control, and therefore $u_o = 0$, for all i.

When stabilizing for transient response, very few control actions are performed. Furthermore, some control options are single acting. Once a generator is removed from service, it is unable to be removed from service a second time. Therefore, the R control cost matrix of (5) becomes time-dependent. When these control types have executed, then their future cost is set to infinity. Equation (7) summarizes the objective function, according to the previous guidelines. The first term, a summation, is the cost due to the difference between the predicted state trajectory and the reference state trajectory.

The second term is the cost of the control.

$$\min_{u_{k+1,\dots,k+K}} \left\{ \begin{matrix} \left(\sum_{i=k+1}^{k+K'} \left(q_i - q_i^{(o)}\right)^T Q \left(q_i - q_i^{(o)}\right)\right) \\ \left(\prod_{i=k+1}^{k+K} R_i u_i\right) \end{matrix} \right\} \quad (7)$$

For rotor angle stability, potential actuation options, u, are shown below [17]. The listed order is one possible arrangement, in order of highest to lowest cost. The control costs, through matrix R, are specified later in the paper.

1. Load shedding.
2. Generator shedding.
3. Dynamic brake.
4. Series capacitance insertion.
5. Shunt capacitance.
6. No action.

The transient stability optimization constraint, (4), is stability through the prediction horizon.

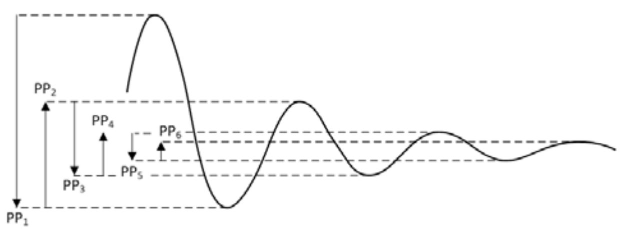

Fig. 1. An example of a stable power swing [1]

Fig. 1 demonstrates the criteria for a response classified as stable. The peak-to-peak amplitude differences are numbered sequentially, with PP_k corresponding to the k^{th} swing. Subsequent peaks must monotonically decrease in amplitude.

$$PP_1 \geq PP_2 \geq \cdots \geq PP_{K''} \quad (8)$$

The prediction horizon, K', is set adaptively according to K". Prediction continues until K" oscillations are completed. For some systems the swing includes multiple modes and (8) may be violated, while the system is on a trajectory towards an overall stable state. Therefore, in this case, the control model continues to integrate into the prediction horizon, and if the subsequent set of peaks becomes monotonic then the system is declared stable. This case is shown in Fig. 2.

For the present problem, the sampling interval is on the order of milliseconds, with a prediction horizon of several seconds. Therefore, K' is on the order of hundreds. Recent proposed systems for voltage control [9] use K' in the order of 2 to 10, which is much shorter than the K' needed for rotor angle stability.

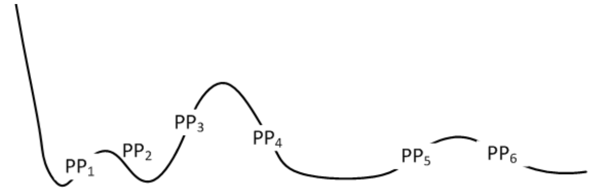

Fig. 2. An example of multimodal stable swing [1]

IV. Implementation of Prediction Based Stability Control

The Kundur two-area test system [18] is selected to demonstrate basic operation of the prediction based stability control approach, for a two-area power system. It is modified by duplicating three of the generators, to give finer granularity in generator shedding options, and adding additional tie-lines between the areas. The loads are a mixture of constant impedance and constant power [18]. The control algorithm is implemented with delays to account for communication latencies and actuation latencies, and to provide time for the algorithm to execute.

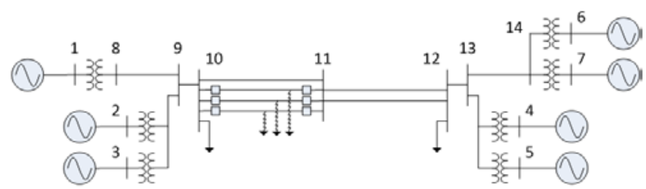

Fig. 3. Kundur 2-area test system [18]

TABLE I
Critical Clearing Time as a Function of the Power Transferred Across the Tie Lines [1]

$P_{L\,12}$, pu	T critical, milliseconds
0.988	480
1.0	300
1.004	150

Consider the case of losing three out of four tie lines between bus 10 and bus 11. Local protection first operates to isolate the faulted buses. However, if local protection fails, for example, if a breaker does not open, then backup protection removes the faulted buses. Backup protection clearing time is a function of designed coordination delays as well as physical constraints like communication latencies. Table 1 shows the critical clearing time that backup protection must achieve, in order to keep the system stable. As the load at bus 12 increases, the minimum clearing time reduces. For any practical system, there is a lower limit below which the backup protection cannot operate. Table 1 demonstrates how that limit affects load.

Consider an example scenario where the expected worst-case backup protection operating time is 450ms after the initial fault. Fig. 4 shows the resulting frequency for a triple line loss between buses 10 and 11, with P12 at unity normalized value, and clearing at 450ms. As indicated in

Table 1, and seen in Fig. 4, the system is unstable. Therefore, reliably transferring this amount of power between the two areas is not possible, without additional controls.

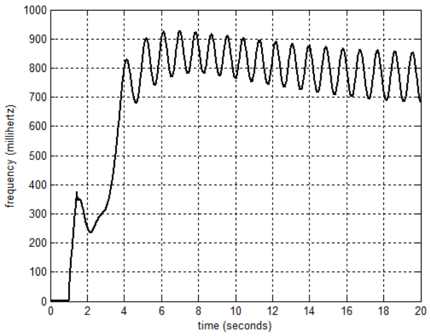

Fig. 4. An unstable system response [1]

The prediction based stability control algorithm continuously monitors the power system, by measuring synchrophasor angles, estimating the internal machine states, and predicting future trajectories. No assumption about the maximum number of lines lost is necessary. It then selects an appropriate control action such as series capacitor insertion or generator shedding, to correct system instabilities. An advantage of this approach over a preplanned scheme is the feedback nature of control. This allows the controls to adapt in real-time to inaccurate measurements and parameter models. With respect to parameter modeling inaccuracies, for the simulations in this section generator parameters are forced to have a 10% error, compared to the actual machine parameters.

The control costs are selected based on the stability of the no-control case. If the model predicts that the system is evolving towards a stable state then it is best to avoid severely disruptive control actions such as load or generator shedding. Incremental control such as series capacitor insertion are allowed if the model predicts that state transients are reduced, or if this allows voltages to remain within tighter boundaries. If the model predicts that the system is evolving towards an unstable state then it is best to avoid waiting. This principle is important because issuing no controls and waiting for the next prediction iteration is an allowed option.

For the Kundur system, the prediction based control algorithm considers generators 2, 4, and 7 for tripping, and insertion of 15% series capacitor compensation at bus 10-11 and bus 11-12. Table 2 lists the normalized control costs for the available controls for this system. Without loss of generality, the control options are kept to a minimum and other possibilities, such as series brake or load shedding, are not included. This helps maintain clarity of the example.

To demonstrate optimizing over network and machine states, the objective function (7) includes network voltages and the generator internal angles. In this case, $q = \{V_i, \theta_j\}, i = 1, \dots, N; j = 1, \dots, M$. The relative weighting is set equal. The reference trajectory for the voltage is the pre-fault voltage level. The reference trajectory for the internal machine angle is the center of inertia angle, with mean subtracted.

TABLE II
THE COST OF THE CONTROLS [1]

No-control result	No action	Series capacitance	Generation shedding
Stable	1	2	∞
Unstable	2	1	3

The synchrophasor measurement availability is set at a rate of 60 per second. The required measurement rate depends on system characteristics. For the systems studied here, sampling rate at sixty per second is adequate. This rate determines the predictive stability model update rate because the internal machine state updates at this same rate, and the iteration interval is set as a multiple of the measurement rate. Fig. 5 shows a timeline for the system evolution, compared to the prediction model.

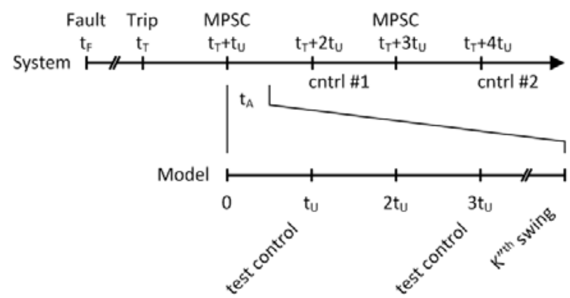

Fig. 5. The time sequence of events [1]

The fault occurs at time t_F. The line trips at time t_T. Once a line trip indication is detected then the control loop (indicated with MPSC, for model prediction based stability control) executes its first iteration, and repeats at an iteration interval of t_U = 50ms. If a control is issued, an extra iteration interval is waited to allow propagation of system transients. A delay of t_D = 50ms is assumed from the MPSC initiates until the control acts. This accounts for calculation time (t_A), communication delay, and actuator latencies. The prediction horizon is adaptive, according to when the K"th swing is found. The value of K" is set at ten and the center of inertia machine angle (8) provides the stability constraint.

Consider again the case of losing three lines and tripping 450ms after fault onset. Tables III and IV, along with Fig. 6 provide the results for this case. The predictive stability control algorithm first runs at 50ms after the tripping time. Table 3 shows the cost of the state deviation from the reference state (column 5) for each of the cases which meet the stability criteria of (8), along with the cost of the control (column 6) according to Table II. The total objective metric, (7), is the product of the last two columns in Table III. The first four columns in these tables list the control actions which meet the stability criteria.

The minimum objective metric for the first iteration, with a value of 3.46 prior to control cost scaling, is for the case when generator number 4 is shed 50ms after initiation of MPSC, and then 15% series capacitance is inserted 150ms after initiation of MPSC. As shown in Fig. 5, the first control action is taken.

At the next iteration instant, at time $t_T + 3T_U$ = 150ms after the initial trip, Table IV shows the simulation results. In this case tripping the generator has sufficiently stabilized the system and given that this option has the lowest objective, with a value of 2.95 prior to control cost scaling, no further controls are selected.

TABLE III
FIRST ITERATION RESULTS FOR THE KUNDUR SYSTEM [1]

+50ms		+150ms		State difference cost	Control cost
Gen	Cap	Gen	Cap		
0	0	4	0	4.18	6
0	10-11	4	0	4.42	3
0	11-12	4	0	4.24	3
4	0	0	0	3.44	6
4	0	0	10-11	3.50	3
4	0	0	11-12	3.46	3

TABLE IV
SECOND ITERATION RESULTS FOR THE KUNDUR SYSTEM [1]

+50ms		+150ms		State difference cost	Control cost
Gen	Cap	Gen	Cap		
0	0	0	0	2.95	1
0	0	0	10-11	2.98	2
0	0	0	11-12	2.96	2
0	10-11	0	0	3.02	2
0	10-11	0	11-12	3.03	4
0	11-12	0	0	2.97	2
0	11-12	0	10-11	3.00	4

For the first two power transfer cases in Table 1, simulations show generator number 4 is tripped at 100ms after the line trip. It is important for the case where the system is normally stable that the control algorithm takes no action. This is affirmed by the P12 = 0.998 simulation case (not shown), with a critical clearing time of 480ms, greater than the operating time of the system without transient stability control taking action. Fig. 6 shows the line frequency after stabilization. Although the frequency deviation is significant, it is reasonable given the severity of losing three out of four tie lines, compared to the small system size. The system is stabilized.

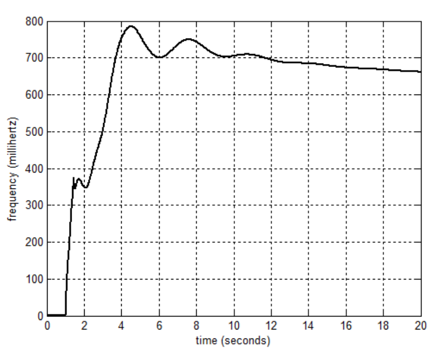

Fig. 6. System response with feedback control [1]

Additional examples and discussions of the proposed wide-area transient stability controller can be seen in [1] and [2].

V. WIND FARM RELATED SUBSYNCHRONOUS OSCILLATIONS

Interactions of sophisticated power electronic controls within modern wind farms with traditional power system components can lead to emergence of SSR phenomena. Such subsynchronous oscillations if left uncorrected can result in severe damage to expensive power system equipment [19],[20]. Our recent presentation [21] showed examples of how such SSR oscillations can be detected in real-time from archived wide-area measurements from Oklahoma Gas and Electric. Specifically it was shown that the SSR detection time decreases as the sampling rate of the measurement signal increases. For instance, using Prony type of algorithms, SSR detection times are 2 seconds, 1.4 seconds and 1.33 seconds for sampling rates at 30 Hz, 120 Hz and 5760 Hz signals, for analyzing 12.4 Hz oscillations while all the analysis was done using the same 1 Hz moving window analysis windows. Additional details can be seen in [21]. The oscillations can be analyzed by ambient noise based engines as well. Using high speed 5760 Hz sampled data from a Digital Fault Recorder (DFR), Frequency Domain Decomposition (FDD) algorithm was used to estimate the modal content of the signals, and the 12.4 Hz oscillations were detected by FDD using a short 1.5 second analysis window as shown in Fi. 7. Basically, the analysis in [21] points to the need for high frequency sampled data for handling SSR related issues in future power systems that are rich in renewable energy sources with complex power electronic controls.

VI. CONCLUSIONS

Wide-area transient stability controls based on model prediction methodology have been proposed in this paper. The controls are shown to be very effective in handling complex high order contingencies while minimizing the impact on customers as well as the number of control actions. Methods for detecting and isolating SSR phenomena related to wind farms have been developed and tested on archived measurements from a real power system. Novel wide-area voltage stability controls have been developed in [22] though they are not discussed in this paper owing to space limitations. The research has addressed stabilizing control designs for addressing the problems of voltage stability, oscillatory stability and angle stability using wide-area synchrophasor measurements.

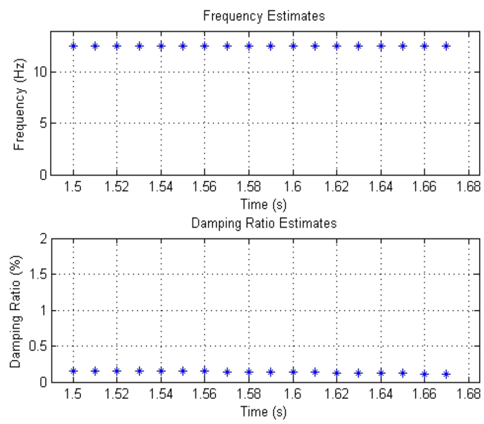

Fig. 7. Detection of 12 Hz wind farm oscillations from 5760 Hz DFR data by FDD [21]

VII. Future Work

Control designs proposed in this research are motivated towards futuristic power systems by assuming an abundance of synchrophasor measurements with no restrictions on communication and computational capabilities. Whereas in the present day power system, synchrophasors are being introduced in a gradual manner with the recent Federal investment awards servings as an important impetus. There is a need to develop a control design road-map that introduces few of the control ideas into the current power system with a planned transition that takes us to the future current designs of this research in a gradual manner. It is important to start implementing some of the wide-area closed-loop control designs in the present day system so that the engineers and operators develop confidence in the technology and concepts while we move forward.

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IX. Biographies

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Hamed Khalilinia received his M.Sc. degree in Electrical Engineering from Isfahan University of Technology (IUT), Iran, 2009 and is currently pursuing his PhD degree in Power System Engineering at Washington State University, Pullman, WA. His research interests mostly include dynamic and stability of power System, power system oscillation monitoring and also smart grid.

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Hierarchical Coordinated Protection with High Penetration of Smart Grid Renewable Resources (2.3)

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***Abstract*--In this paper, new Hierarchically Coordinated Protection (HCP) concept that mitigates and manages the effects of increased grid complexity on the protection of the power system is proposed. The concept is based on predicting protection circumstances in real-time, adapting protection actions to the power system's prevailing conditions, and executing corrective actions when an undesirable outcome of protection operation is verified. Depending on an application, HCP concept may utilize local and wide area measurements of the power system parameters, as well as non-power system data, such as meteorological, detection of lightning strikes, outage data and geographic information. Since HCP introduces intelligence, flexibility and self-correction in protection operation, it is well suited for the systems with increased penetration of renewables where legacy solutions may be prone to mis-operate. Such instances are unintended distance relay tripping for overloaded lines, insensitive anti-islanding scheme operation, and inability to mitigate cascading events, among other system conditions caused by renewable generation prevailing in future grids.**

I. Introduction

With the increasing energy demand, deregulated power market, environmental concerns and favorable government policies on integration of the renewable generation into the power grid, new challenges and needs in the power grid protection are introduced. The structure of the conventional grid with a few large, centralized generation sources at the transmission system that supply passive load at distribution system is changing towards the network with many renewable distributed generation (DG) sources connected at all voltage levels. In the last decade, due to significant development in the power electronics and digital control technology, a number of large scale, offshore and onshore wind generation units have been installed in the transmission system. Over the time, the transmission system structure becomes more complex and operation scenarios are changed now due deferral of the grid infrastructure upgrade. The system is planned to operate with tighter margins, less redundancy, reduced system inertia and fault levels, and under exemplified dynamic grid operating phenomena such as power and voltage oscillations, as well as voltage, frequency and angular instability. These phenomena may cause new dynamic behavior in the typical protection measurements such as voltage, current, frequency, power, etc. Such changes in the measurement properties may deteriorate protection system performance leading to unintended operation or mis-operation.

Many methods aiming at finding ways for detecting, preventing, and mitigating the cascading events are proposed in the literature. Considering that the cascading phenomena are very complex due to the diversity of failures and interactions, it is not possible to accomplish an exhaustive simulation of all possible combinations of N-m failures in a power system. Thus, different researchers have made various assumptions to reduce complexity in modeling and simulating the cascading outages [1-4]. Some researchers have studied the statistical properties of the power system network [5, 6], other used dynamic event tree analysis [7], expert system [8], pattern recognition [9] etc. to detect cascading events. These methods are either complex to implement and use in the real time applications or simply reduced to assessing the risk of cascading outages and may be used in the system planning stage only.

In addition, installation of DG at the distribution level changes the distribution system behavior from passive network that transfers power from substation to the customers in a radial fashion to an active network with generation sources causing bidirectional flows. This change may affect protection coordination and selectivity, may introduce power quality disturbances and may cause unintentional islanding. Since the island is unregulated, its behavior is unpredictable and voltage, frequency and other power quality parameters may have unacceptable limits. The out-of-phase reclosing is possible and safety of the public or utility workers may be threatened. Thus, the islanded systems should be de-energized promptly.

At the transmission levels, transfer trip is used to prevent islands in the network, while at the medium and low voltage levels active or passive islanding detection scheme are utilized. The passive methods [10-15] discriminate islanding from normal condition based on the measurements of system parameters at the point of common coupling (PCC) with the

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grid. Those measurements or some features extracted from them are compared to the predefined thresholds and are characterized by large non detection zone (NDZ) [16, 17]. Threshold settings for those relays are difficult to calculate because some other events in the grid may cause transients that trigger these relays. On the other head, active methods [18-22] are categorized by smaller NDZ than passive, but those methods inject small disturbances and may cause power quality and stability problems during normal power grid operation. The active methods are embedded into a control circuit of the power inverter and they are designed to inject small disturbances into the DG output. The active methods have small NDZ but they may deteriorate power quality during normal power system operation [23]. Besides, active methods may mis-operate in the system with multiple DGs due to mutual interference and cancelation of the injected disturbances [24] or they may have an effect on the system stability [25].

The paper is organized as follow. In Section II conceptual solution based on the HCP paradigm is described. Section III provides simulation details and illustrates benefits comparing to the existing approaches. The conclusions are summarized in Section IV followed by suggestions for the future work. At the end of the paper an elaborate list of relevant references is given.

II. Hierarchical Coordinated Protection Approach

The aim of this study is to propose conceptual solution that will improve legacy protection operation and mitigate negative effects of the increased grid complexity on the system reliability and power quality. The key questions being faced relates to whether protection schemes should provide more flexibility in their behavior, how flexibility may be justified and how potential uncertainty in protection behavior may be assessed and corrected. As a response to this need the Hierarchically Coordinated Protection (HPC) concept is defined. The proposed approach relies on the three protection layers, shown in Figure 1: predictive protection, adaptive/settingless protection, and relay operation correction in case of unintended tripping. Each layer utilizes new data to perform an analysis, and only the right combination of the analysis at each layer will provide full benefits of the approach. The selection of analysis per each layer is highly dependent on the protection application. The main idea behind each layer is listed next.

The Predictive Protection layer recognizes conditions that lead to the major disturbance using statistics from the systems' earlier contingencies such as weather patterns, lightning, strikes, animal and bird migration patterns, component outage history, etc. This layer compares the unfolding conditions to the ones that lead to the major disturbance in the past and may trigger high intensity computational methods to verify whether the prevailing conditions resemble any previous system conditions. Since this layer may anticipate disturbance it may provide necessary "breathing time" for protection system to adjust bias between dependability and security, which may be implemented through triggering selectable relay setting groups.

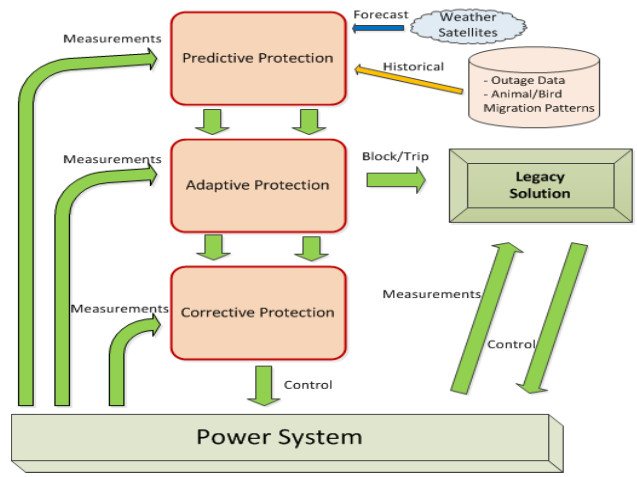

Fig. 1. Hierarchically Coordinated Protection Concept

The next is the Inherently Adaptive Protection layer that adjusts its tripping logic based on feature patterns of waveform measurements extracted in real-time. Such data patterns are matched to the patterns obtained during learning process that includes thousands of potential system conditions. This approach enables flexibility and robustness in protection behavior. Using this approach it is feasible to design a protection scheme that gives equal importance to dependability and security of protective relay operations. This was hard to achieve simultaneously with legacy protection schemes since designing protection systems for trade-offs between dependability and security was common in the past.

The third layer or Corrective Protection acts as a verification tool capable of assessing correctness of relay operation. This tool is characterized by high accuracy, but it has high computational burden, and may have unacceptable operational latency if used in real-time system operation. Thus, this tool should be triggered when a legacy protection scheme operates, and should be active immediately after to correct the original relay action if needed.

Further, two examples that utilize HCP will be presented. In the first example, HCP concept is used to enhance distance protection practice in transmission system that may be prone to misoperation in the overload and power swing condition. This relay misoperation may further lead to unfolding cascading events and system blackout. In the second example, HCP concept is used to detect islanding condition and reduce the negative effect of the active anti-islanding scheme on power quality in the distribution system.

A. Cascading Event Detection and Mitigation

An example of the novel transmission system protection philosophy that relies on HPC design concept is shown in Figure 2. This approach provides enhancements in system-wide monitoring of power system component condition, reliable protective relay operation and capability for corrective actions. The scope of the each HPC layer is described next.

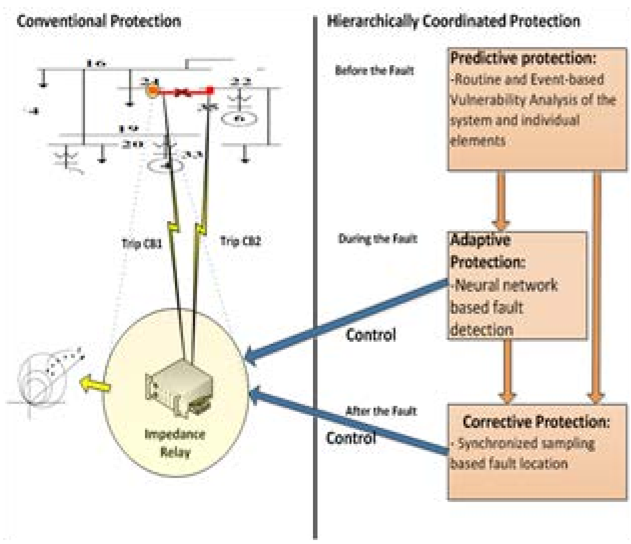

Fig.2 Hierarchically Coordinated Protection Concept for Cascading Event Detection and Mitigation

Predictive Protection: The system monitoring and control tool that performs routine vulnerability analysis of operating condition of the whole system and individual elements is deployed at the control center level and alert signals are sent to the substation level to closely monitor relays placed at the most vulnerable components [26]. The prediction of where the protection mis-operation may occur gives an early warning of how the contingencies may unfold. In addition, the statistical data and information from weather related tracking systems, history of the component outages, and power system operating conditions that may lead to the major disturbances, etc are used to anticipate occurrence of a fault condition may be utilized as well. At this point, due to lack of non-power system data only the vulnerability analysis tool is used.

Inherently adaptive protection: At the substation level, neural network based fault detection and classification algorithm is employed [27]. Its tripping logic is based on feature patterns of waveform measurements that are recognized on line and matched to the patterns obtained during learning process that includes thousands of potential fault conditions. This approach does not have settings and hence avoids mis-operation due to inadequate settings allowing for an inherently adaptive action to optimize the balance between dependability and security.

Corrective protection: At the substation level, fast and accurate synchronized sampling based fault location and event tree analysis are used to detect incorrect line tripping sequence and incorrect relay logic operation respectively [28]. Upon transmission line tripping, fault location algorithm will immediately validate correctness of relay's operation and in case of unconfirmed fault condition; the system component (transmission line) will be quickly restored. The relay logic will be checked as it executes and if an incorrect sequence is detected, the relay action will be corrected.

As an additional example of corrective action, highly accurate distribution system fault location is possible by combining lightning location data form the U.S. National Lightning Detection Network with fault monitor disturbance data and distribution feeder location (GIS) data [29]. The data latency is several seconds and may be used in the corrective protection to verify the fault location determination in the system. Moreover, animals and birds cause large number of outages in overhead distribution systems. The frequency of animal and bird related outages depend on the area, season and time of the day. The historically obtained outage patterns and animal/bird migration patterns may be used to verify the fault location determination in the distribution systems [30].

B. *Anti-islanding Protection*

The new protection approach to reduce negative effect of the active anti-islanding schemes on the power quality in the distribution system is presented next. The framework of the proposed approach consists of the following:

Predictive Protection: For this purpose, non-conventional power system data, the statistical historical event data and information from weather related tracking systems, history of the component outages, etc. may be used to calculate predictive indices. These indices are used to trigger corrective part of the approach. In this study due to lack of non-conventional power system data prediction indices are generated randomly.

Inherently Adaptive Protection: Using measurements at the PCC, Support Vector Machine (SVM) based islanding detection method is utilized [33]. The features from current and voltage signals are constantly extracted and fed to the SV models obtained in the offline training. This approach does not have NDZ and operates independently of generation/load mismatch. It shows great robustness to the external grid events, such as faults and component switching.

Corrective Protection: At the corrective layer, an active anti-islanding method is used. The active methods are characterized by high accuracy; however they may have negative impact on the system power quality during normal system operation. Thus, this method will be normally inactive and prediction indices will be used to trigger the method for short period of time. The corrective layer will sent block/trip signal to the circuit breaker at PCC.

III. MODELING AND SIMULATION RESULTS AND DISCUSSIONS

In this section HPC solution is presented using modeling and simulation examples for two applications and major benefits are assessed when compared to the legacy solutions.

A. *Cascading Events Detection and Mitigation*

In order to illustrate the use and operational efficiency of the proposed Hierarchically Coordinated Protection concept for the transmission applications, the IEEE 39-bus New England test system shown in Figure 4 is utilized [31]. The two most vulnerable lines according to their vulnerable indices are: Line 21-22, 28-29. The outage of those lines will have a large impact on the system stability since the original loads in those two lines will be redistributed to the neighboring lines causing more overloading issues. The system monitoring tool will inform the local relay monitoring tool on those lines to start monitoring relay operations closely. A series of disturbances occur in the system, with the event sequence shown in Figure 5. The related system components are marked in Figure 4.

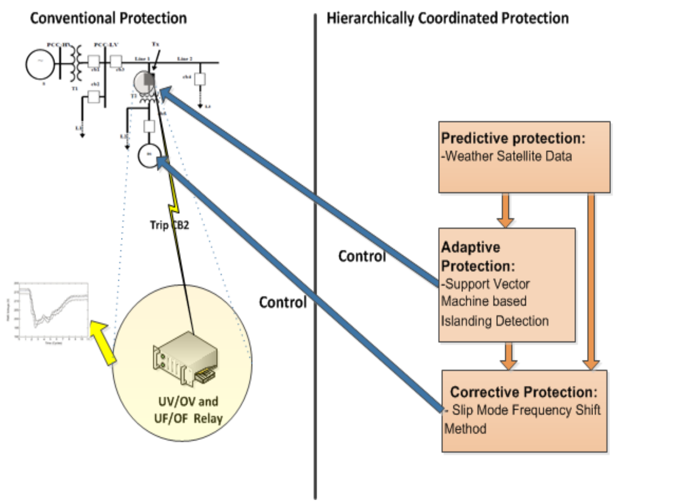

Fig. 3. Hierarchically Coordinated Protection Concept for Islanding Detection

These two faults are permanent faults and thus isolated by the relay actions. After the line 21-22 is removed due to the first fault, the top 2 most vulnerable lines are changed to: Line 28-29, 2-3. After the line 28-29 is removed due to the second fault, the top 2 most vulnerable lines are changed to: Line 23-24, 26-29. This contingency may cause relay at Bus 26 of Line 26-29 to mis-operate. The trajectory of impedance seen by that relay is shown in Figure 6 with the event sequence labeled. Although the two faults are not related to the healthy line 26-29, the power swing caused by the two faults will have an impact on the distance relay. It observes Zone 3 fault at 1.627s after the second fault clearing until the trajectory leaves Zone 3 circle at 1.998s. The distance relay may trip Line 26-29 when its Zone 3 timer expires. As a result, buses 29, 38 will be isolated from the system, including the G9 and loads at bus 29. This will results in the oscillation in the rest of the system and further cascading outage may happen.

The mentioned situation can be prevented by the proposed solution and local monitoring and protection tool. When the first fault occurs, the faulted line 21-22 is removed and no other operation happens. The relay monitoring tool for the relay at Line 21-22 will inform the system monitoring tool about the relay operation for the three-phase fault. The system security analysis is activated after the first fault. An alert signal will be sent to the local relay monitoring tool at vulnerable lines at this stage. Since the first fault will not degrade the system stability very much, the local relay monitoring tool will not be authorized to intervene with relay operations at this stage. When the second fault happens and Line 28-29 is removed, the local relay monitoring tools for the most vulnerable lines 23-24 and 26-29 will be authorized to correct the potential relay mis-operation or unintended operation in real time since the mis-operation of those relays will directly separate the system. After the second fault, the local relay monitoring tool at Line 26-29 will draw a conclusion to block the relay from tripping for Zone 3 fault. That information will be sent back to the system level. The system level will issue appropriate control means to mitigate the disturbances. In an actual large scale system, it is impossible that one or two contingencies like the ones discussed in this scenario can cause

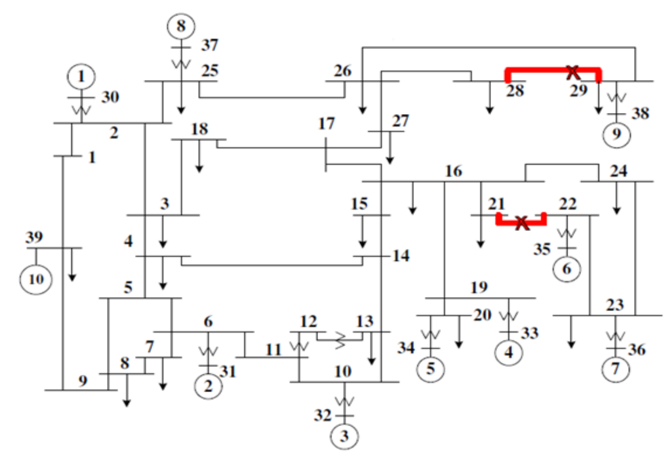

Fig. 4. IEEE 39-bus system

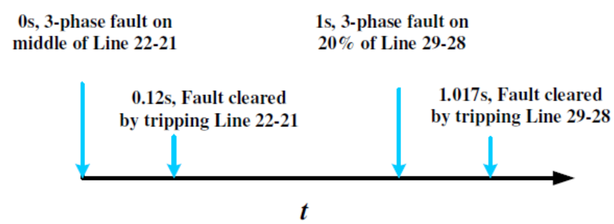

Fig. 5. Event Sequence

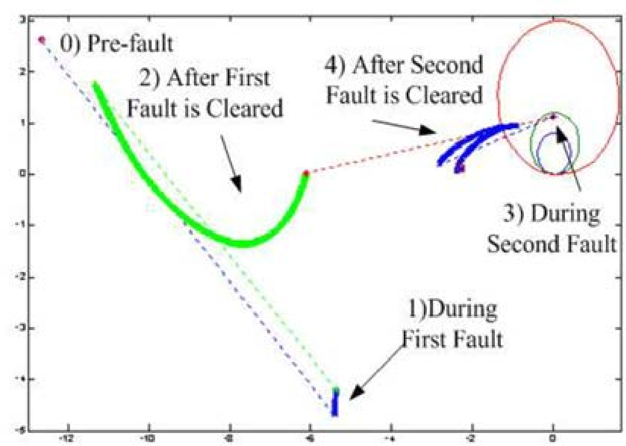

Fig. 6. Trajectory of Impedance

large scale system oscillation. Usually there is enough time to coordinate the system-wide and local analysis in the initial stages of the disturbances to mitigate the impact of the disturbances before they unfold into the large one. An interactive system-wide and local monitoring and control means can help reduce the probability of a cascading blackout since the disturbances can be fully analyzed at both the local and system level.

B. Anti-Islanding Protection

In order to demonstrate the proposed concept, a study case using IEEE 13-bus test system shown in Figure 7 and modeled using PSCAD/EMTDC is presented [32]. A 5 kVA single phase 120V DG is connected to A phase of the node 692. The

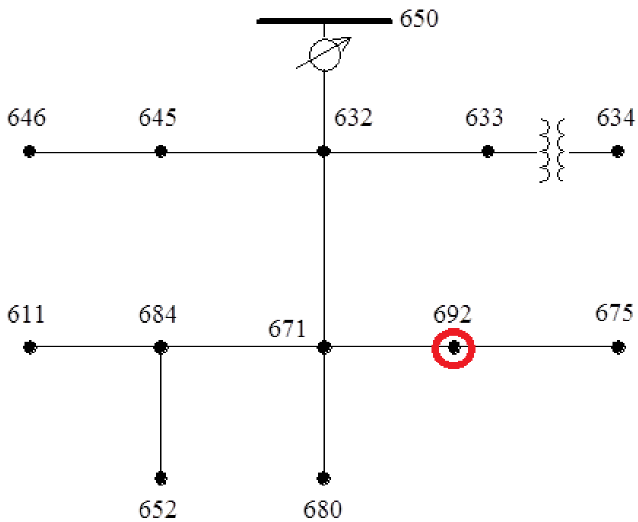

Fig. 7. Diagram of the IEEE 13 distribution test system

decoupled current control interface presented in [22] is used in the study. The inverter control is adjusted so that DG operates at unity power factor. In this arrangement DG supplies maximum active and zero reactive power to the grid. More details about proposed method may be found in [33].

The prediction trigger signal is artificially generated and sliding mode frequency shift method [19] is activated. Twenty cases seen in Table I, ten islanding and ten non-islanding are randomly simulated and all islanding cases were detected by the adaptive layer of the proposed framework. This is obvious sequence of events since active anti-islanding method injects disturbances into the signal and it takes time for the system to respond to the disturbance. To detect islanding condition using adaptive layer it takes 0.1s while the detection time for the sliding mode frequency shift is more than 0.15 s.

IV. Conclusions

The new proposed approach:

- has superior performance when compared to the existing solutions
- co-exists with the legacy solutions and only supplements its normal operation
- has self-corrections and verification tools
- makes a way for adaptive protection to be accepted as an alternative to conventional protection principle

V. Future Work

The future work involve exploring and assessing benefits of the proposed paradigm to the proposed power system applications in the protection area taking into account further implementation details.

VI. Access to Products

The findings of the research may be found in the research papers and reports published by PSERC. Details related to implementation are contained in the related Ph.D. Dissertations, as well as in the Dissertation of the co-author.

TABLE I
Generated Test Cases

Cases	**No. of Events**
Fault Event	4
Capacitor Stitching	2
Static Load Switching	2
Motor Load Switching	2
Islanding	10 (±20 % active power and ±3% reactive power mismatch)

VII. Acknowledgment

The authors gratefully acknowledge the contributions of Slavko Vasilic, Nan Zhang and Hongbiao Song whose dissertation work results were utilized to illustrate the concept proposed in this paper.

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IX. Biographies

Mladen Kezunovic (S’77-M’80–SM’85–F’99) received the Dipl. Ing. , M.S. and Ph.D. degrees in electrical engineering in 1974, 1977 and 1980, respectively. Currently, he is the Eugene E. Webb Professor, The Director of the Smart Grid Center, Site Director of NSF I/UCRC “Power Engineering Research Center, PSerc”, and Deputy Director of another NSF I/UCRC “Electrical Vehicles- Transportation and Electricity Convergence, EV-TEC”. His main research interests are digital simulators and simulation methods for relay testing, as well as application of intelligent methods to power system monitoring, control, and protection. He has published over 450 papers, given over 100 seminars, invited lectures and short courses, and consulted for over 50 companies worldwide. He is the Principal of XpertPower™ Associates, a consulting firm specializing in power systems data analytics. Dr. Kezunovic is a Fellow of the IEEE, IEEE Distinguished speaker, a member of CIGRE and Registered Professional Engineer in Texas.

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A National Transmission Overlay (1.2)

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Iowa State University

***Abstract*—This paper presents a five-step design framework of a high-capacity transmission system at the national level. This framework is applied to the U.S. power system to design robust transmission overlays for four future scenarios, including a reference case, high offshore wind, high solar, and high geothermal. Simulations of aggregated U.S. power system models suggest that a national transmission overlay provides benefits via lower operational and investment costs, increased resilience and flexibility, reduced CO_2 emissions, and improved dynamic performance.**

I. Introduction

THIS paper considers a design process for a high capacity interregional transmission overlay. The process designs the overlay as a single integrated system, to provide economic, environmental, and system performance benefits at the national level [1]–[3]. The work is motivated by the fact that areas where renewables are most economic are generally remote from load centers, so that for a high renewable future, high capacity transmission can facilitate use of the most economic resources.

There has been previous interest in considering high-capacity, multi-regional transmission overlays within the U.S. [4]–[8], as well as within Europe [9]. The work reported in this paper adds to this growing body of literature by providing an explicit design process, by incorporating within this process the effects on frequency dynamics, and by providing some resulting U.S. designs. Specifically, we propose a five-step design framework of a National Transmission Overlay for the U.S. power system to facilitate the growth of wind, solar, nuclear, geothermal, and other forms of generation over the next 40 years. Using this methodology, four investment scenarios have been investigated for the future U.S. power system. We perform optimization studies to find the optimal transmission investments. We also evaluate the emissions and dynamic performance of the overlay designs.

This paper is organized as follows. Section II describes the new design approach, Section III presents and analyzes study results, and Section IV concludes the paper.

II. Design Framework of a National Transmission Overlay

This work has developed an innovative planning framework that consists of five main steps: generation planning, transmission candidate selection, network expansion optimization, investment plan evaluation, and dynamic assessment. The planning process is conceptualized in Fig. 1. The steps are described in the following five subsections.

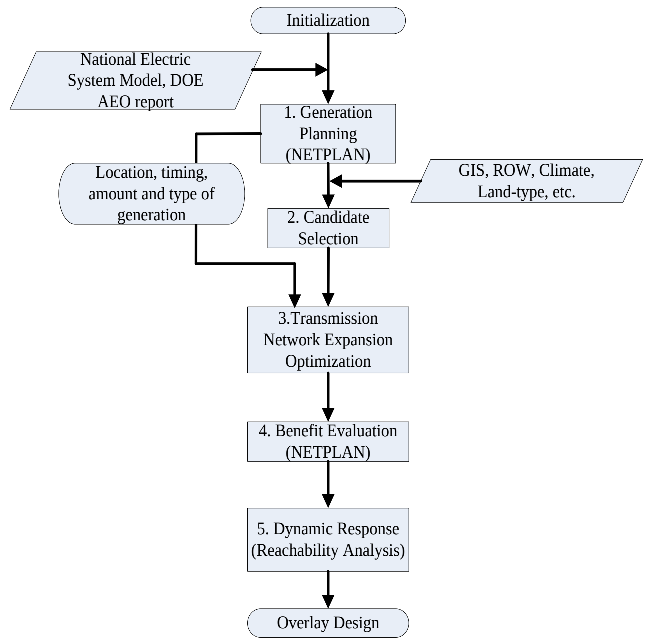

Fig. 1. Five-step transmission design framework.

A. Generation Planning

This step determines the amount, type, location, and timing of future generation capacity investment using NETPLAN software [11]. The objective is to minimize the total cost which includes the generation investment cost, operation and maintenance cost, fuel production and transportation cost. In this step, transmission is represented with unlimited capacity.

Four generation portfolios were designed: a reference case, a case with high-offshore wind, a case with high solar and a case with high-geothermal[1]. The reference case assumes that major types of conventional generation, including nuclear, hydro, combustion turbine, and coal-fired plants, maintain investment trends consistent with the projections for 2011–2035 from the U.S. Energy Information Administration (EIA) [12]. This reference case models heavy investment of inland wind, reaching 40% penetration (by energy) in 2050. For the high-offshore wind case, about 100GW of in-land wind is replaced by offshore wind generation. The high solar case models high solar-PV and high inland wind. The high-geothermal case replaces the solar PV in the high solar case with geothermal generation, mostly located within Western Electric Coor-

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[1] Data for our studies are adjusted from [12], [13]. Location-specified renewable energy capacity factor and investment cost data for each node are adapted from references [4], [5] and [14].

dinating Council (WECC) Interconnection. These cases were developed using data on existing generation from a detailed national production cost model database [15]. Our base case contains 62 nodes (shown in Fig. 2), 142 existing transmission paths, and 15 different generation technologies that are already developed or under development.

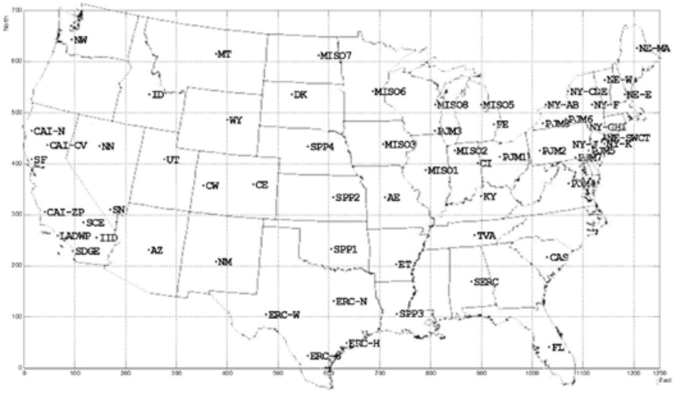


Fig. 2. 62-node representation of the continental U.S.

B. Transmission Candidate Selection

This step selects transmission candidates between node pairs based on factors which may influence transmission investment decisions, including right-of-way availability, economic value, restricted land including American Indian reserve and national forests, land type, population density, forest, lightning density, wind and ice-loading. An iterative reweighting minimum spanning tree algorithm was developed to perform this step. A total of 371 candidate transmission paths were selected. These candidate transmission paths are used as inputs in the next step. The set of candidate transmission paths is plotted in Fig. 3.

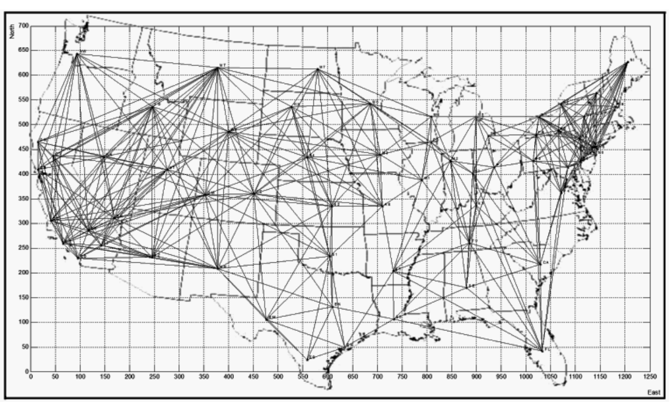


Fig. 3. Transmission candidate set of the U.S. 62 nodes model.

C. Network Expansion Optimization

In this step, a mixed integer linear programming (MILP) model was utilized to optimize transmission investments up to year 2050, using inputs of a generation portfolio from Step 1 and the selected transmission candidates from Step 2. The objective is to find the transmission investment plan (where, when, what technology, and how much capacity) which minimizes total investment and production cost subject to power balance, DC power flow, generation capacity, and transmission loadability constraints. Existing and future generation capacities are inputs. Thus, the decision variables are the transmission investments. Non-linear constraints in the DC flow investment model have been eliminated by using a disjunctive model [16] extended to allow for multiple parallel circuits. Selectable transmission technologies include 500kV EHVAC, 765kV EHVAC, 600kV HVDC and 800kV HVDC, which are today's most mature transmission technologies for high-capacity bulk power transmission. All costs were discounted to 2010 dollars. We develop four designs, one for each of the four cases. The problem statement is summarized below:

Minimize (over 40 years):

Transmission investment cost +
Gen. production cost + Levelized transmission losses[2]

Subject to:

Power balance in each node
DC power flow constrains (in disjunctive format)
Generation capacity constrains
Investment decision variables set to be binary

D. Investment Plan Benefit Evaluation

This step quantifies the performance of each designed overlay. It is accomplished using NETPLAN's multi-objective solver, which computes cost, resilience and emissions [11].

E. Dynamic Assessment

In this step, the candidate transmission overlay design is assessed dynamically using reachability analysis [3]. The reachable sets (flow tubes) enclose all possible trajectories of the dynamic system response. They are computed by representing disturbances and parameters as sets [17], [18]. The assessment is based on system frequency metrics[3] during a sudden load/generation unbalance. The method can indicate whether a transmission design will violate frequency performance requirements.

For illustration, we apply this technique on the U.S. system with a new EHVAC and HVDC transmission overlay. We highlight the control capabilities of the HVDC lines to improve the frequency response of asynchronous interconnections, and to transmit the variability of renewable sources within synchronously connected areas.

1) Model Aggregation:

The 62-node U.S. power system is aggregated into 13 nodes to match data for an equivalent HVAC transmission system that captures existing inter-regional transmission capacity [1]. The candidate EHVAC and HVDC transmission and generation expansion plan (steps 1 to 3) is also aggregated accordingly. An example of a transmission system overlay that was studied is depicted in Fig. 4.

[2] Generation production costs are computed without losses, in Step 1; transmission losses depend on transmission technologies selected and are therefore computed in Step 3, separate from generation production costs.

[3] Frequency response is an important reliability metric [19], especially under high renewable penetration [20]–[22].

2) Dynamic Power System Model:

The power system frequency dynamics are modeled by a linear time-invariant system. Equivalent aggregate linearized models of conventional generators with speed regulators are modeled in each node [19]. The HVAC transmission systems are modeled by their network susceptance matrices. The new HVDC lines linking interconnections are equipped with frequency-sensitive controls [23]–[26], whereas existing HVDC lines are represented by constant power flows (hence, they do not affect dynamics). HVDC lines linking areas within an interconnection are furnished with a washout filter to transmit “high-frequency” variation (on the order of 0.04 Hz or higher) of wind power from areas of low inertia to areas with high inertia. We model the net load (renewable power generation minus load) during the transient as an unknown-but-bounded disturbance. Also, we introduce parameter uncertainty in the inertia of the aggregated reduced-order system model.

The modeling approach is conceptualized in Fig. 5 using a generic 4-area system. Here, areas a, b, and c are connected synchronously (forming an interconnection). Area d connects through an asynchronous speed-sensitive HVDC transmission line for frequency support. Additionally, an HVDC line within the interconnection transmits variability from area b to a. All areas contain one equivalent generator with inertia. In each area, the power injected by conventional generation and renewables, and by external HVAC and/or HVDC transmission is equal to load consumption at steady state.

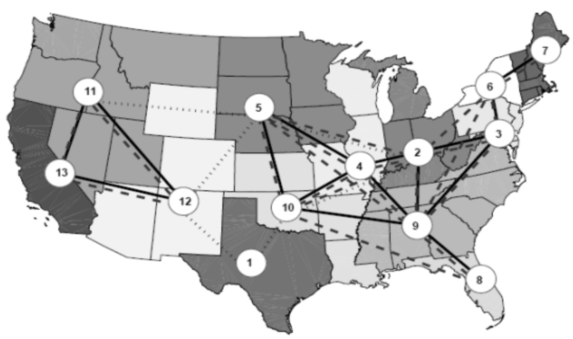


Fig. 4. Reduced national interconnection overlay. Existing HVAC (solid), HVAC overlay (dashed), HVDC overlay (dotted).

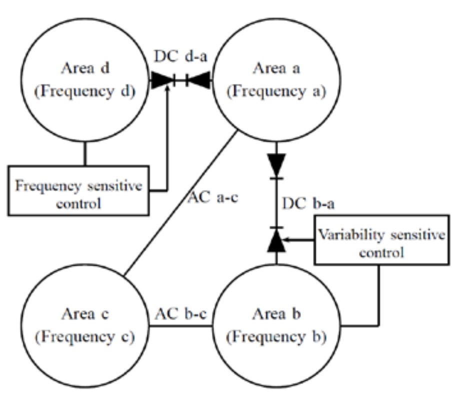


Fig. 5. Multi-area power system setup with inter-area HVAC and HVDC transmission lines.

3) Design Verification:

The computation of reachable sets (represented as zonotopes) is performed in an iterative step-wise fashion. The design is verified by inspecting whether the system trajectories remain within predefined limits for each scenario. Also, the reachable set size can be used as a metric for comparison among various planning scenarios.

III. RESULTS

The optimization problem formulation and dynamic verification routines were coded using MATLAB. CPLEX v12.5 was used to solve the coded optimization problems. The MILP model is solved on a server with 24 CPUs and 47GB memory. INTLAB v6.0 was used to perform interval operations in the system verification process [27].

A. Transmission Overlay Design

The optimization problem size and solution information is summarized in Table I. All costs have been discounted to 2010 dollars. The results of step 1 (Section II-A) are displayed in Fig. 6. These show the accumulated generation capacity of each technology during the 40 year planning horizon for the four portfolios. The transmission candidate set of step 2 is shown in Fig. 3. The results of the transmission network expansion optimization (Section II-C) are provided in Fig. 7–Fig. 10, respectively, one case for each of the four generation portfolios. Major transmission investments are summarized in Table II. From the results, we see that the main transmission investments common to all four cases are:

- near New York State and around the lower Great Lakes;
- from the East Central Area Reliability Coordination Agreement zone to Southeastern Electric Reliability Council including Florida;
- within the Midwest Independent System Operator region which connects rich wind resources in the Midwest to major load centers in the East;
- near the San Francisco Bay area and the Greater LA area.

All these major investments are located near major load centers across the U.S. In particular, the high geothermal case has significantly more transmission investment circuits than other cases. Bulk transmission which connects the WECC with the Eastern Interconnection, to provide transmission for eastward-flowing geothermal energy, is salient in the results. The benefits of these overlays, in terms of cost and emissions, are summarized in Table III.

B. Dynamic Assessment

Two case studies are performed to illustrate the dynamic behavior of the reduced-order US power system shown in Fig. 4. Details about the reachability analysis problem implementation are provided in Table IV.

TABLE I: MODEL AND SOLUTION DESCRIPTION

Case	Reference	High Off.	High Solar	High Geo.
# of Variables	1,855,612	1,855,612	1,855,612	1,855,612
# of Constraints	1,918,260	1,918,260	1,918,260	1,918,260
# of Binary variable	3,244	3,244	3,244	3,244
Solution Time (hrs.)	31.01	46.59	32.59	25.31
# of Lines Built	276	235	312	329
Total Circuit-Miles	88,800.4	79,873.5	92,477.2	108,355.9
Investment Cost (2010B$)	564.965	516.653	590.797	739.667

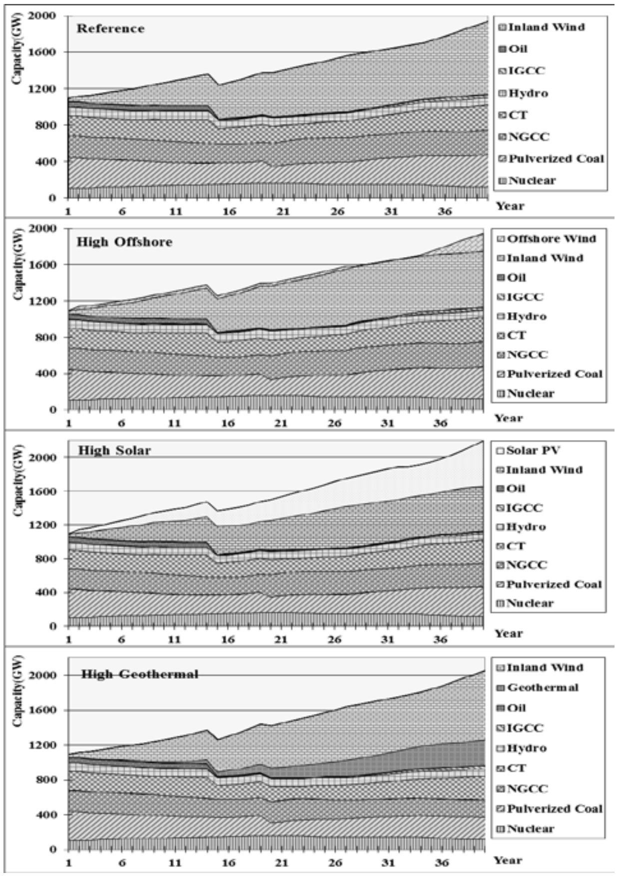


Fig. 6. Four generation investment portfolios from year 2010 to 2050.

TABLE II: MAJOR TRANSMISSION INVESTMENT

Case	Tech	From*	To*	# of Lines	Ckt-Miles	Capacity (GW)	Cost (2010M$)
Reference	500kVAC	P6	N5	16	1696	30.74	6921.15
	800kVDC	M6	M2	15	9150	90	59411.61
	600kVDC	M3	M1	10	3390	30	16531.45
	765kVAC	P3	M2	9	1647	27.02	7628.04
	800kVDC	FL	CI	9	8541	54	45956.07
High Off-shore	765kVAC	M2	P1	14	2464	43.14	9449.90
	800kVDC	M6	M2	12	7320	72	47529.29
	765kVAC	P8	P6	10	2040	27.92	7877.52
	800kVDC	FL	CI	7	6643	42	35743.61
	800kVDC	P3	TV	6	3588	36	21970.00
High So-lar	500kVAC	CI	P1	23	2461	43.91	7814.02
	500kVAC	P6	N5	16	1696	30.74	6921.15
	500kVAC	M2	CI	13	1456	24.08	5034.25
	800kVDC	M6	M2	13	7930	78	51490.06
	765kVAC	CI	P1	8	856	34.37	3245.68
High Geo.	800kVDC	M6	M2	21	12810	126	83176.25
	765kVAC	P6	N5	16	1696	69.17	8388.80
	500kVAC	CI	P1	16	1712	30.55	5435.84
	800kVDC	M2	P1	16	2816	96	38268.48
	800kVDC	M1	TV	10	3380	60	28589.47

*Please refer to Fig. 2 for the location of each node.

TABLE III: Benefit of Transmission Overlay#

Case	Expanded Transmission				Fixed Current Transmision
	Ref.	High Off.	High Solar	High Geo.	
Gen. Inv. Cost(T$)	1.766	1.731	1.752	1.735	2.523
Tran. Inv. Cost(T$)	0.565	0.517	0.591	0.740	0
Gen. Prod. Cost(T$)^	3.005	2.978	3.002	2.995	3.271
Total Cost(T$)	5.336	5.226	5.345	5.470	5.794
Emission (10^{10} short ton)	5.135	5.448	5.072	5.112	5.812

#All costs have been discounted into 2010 dollars.

^Generation production costs include fuel costs and O&M costs.

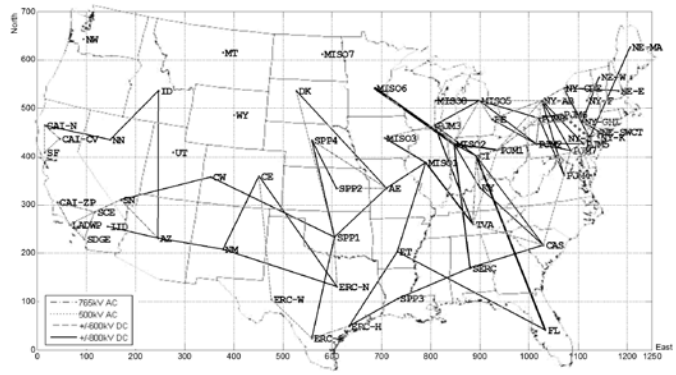


Fig. 7. Transmission investment for the reference case[4].

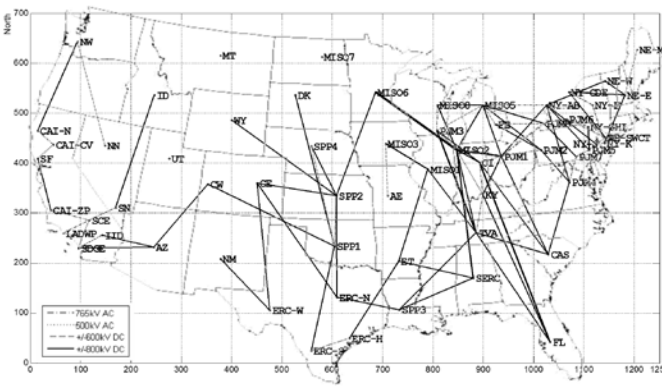


Fig. 8. Transmission investment for the high offshore wind case.

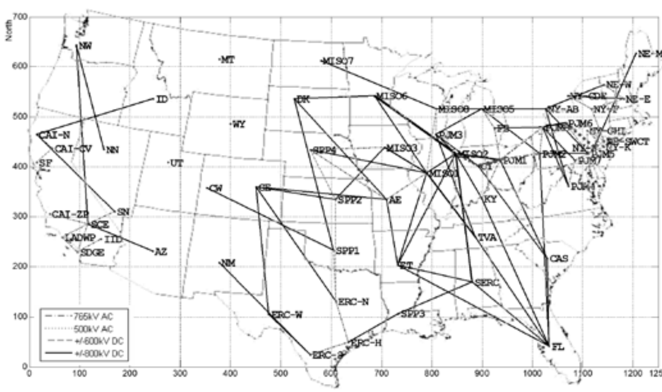


Fig. 9. Transmission investment for the high solar case.

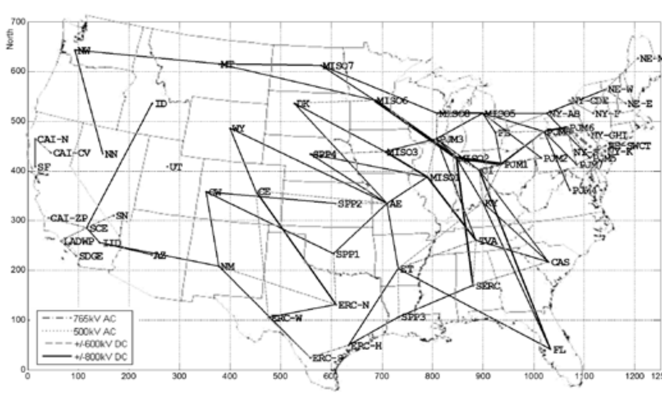


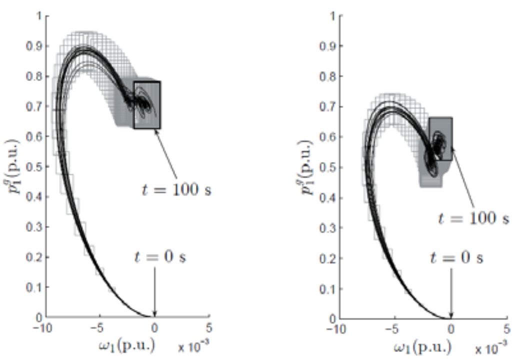
Fig. 10. Transmission investment for the high geothermal case.

[4] In Figs. 7–10, line widths roughly reflect the amount of circuits invested.

TABLE IV
REACHABILITY ANALYSIS IMPLEMENTATION DETAILS

Case study	1	2
Number of states	68	74
Step size (s)	0.01	0.01
Simulation time (s)	100	100
Number of computed zonotopes	10000	10000
Simulation cost (min)	14.76	28.03

In the first case study, frequency-sensitive HVDC branches are linking the three U.S. asynchronous interconnections. Figures 11-a and 11-b contrast the response sets of area-1 frequency without and with dynamic support through the HVDC lines from the other two neighboring areas (10 and 12). An unknown-but-bounded load-generation unbalance in area 1 was applied at t = 0 in the arbitrarily selected range [650, 750] MW. The variable p^g_1 represents the aggregated generation in area 1. It can be observed that there is improvement in the minimum frequency of area 1, which implies that a high-capacity HVDC link with frequency regulation capability can be beneficial. Figure 12 shows projections of the bounding sets of states (frequencies) of three selected areas in the three interconnections. Only 1 out of 100 computed zonotopes is plotted.



(a) Without HVDC support (b) With HVDC support

Fig. 11. Area-1 frequency response with and without frequency-sensitive HVDC lines. Zonotopes (gray) and deterministic simulations (solid).

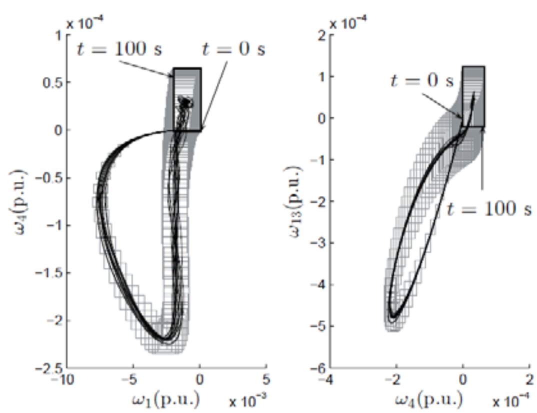
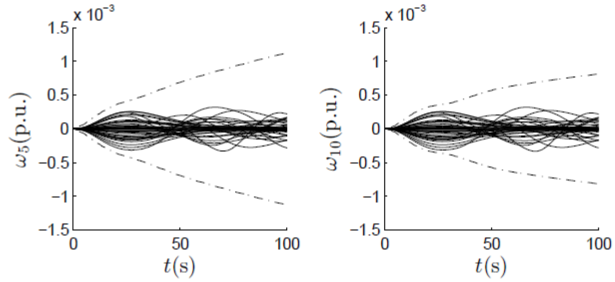
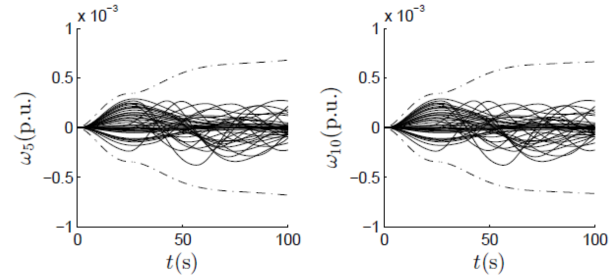


Fig. 12. Possible frequency trajectories of three areas with frequency-sensitive HVDC interconnection.

In the second case study, we show positive impacts on frequency dynamics with new EHVAC and HVDC (that is transmitting variability) within an interconnection, in Fig. 13. The renewable power fluctuations are in areas 5 and 10 and each belongs to the interval [−0.1, 0.1] p.u. This study (cf. Fig. 13-a and -b) indicates that the new transmission lines will reduce the maximum frequency deviation.



(a) Without HVAC-HVDC overlay



(b) With HVAC and HVDC overlay

Fig. 13. Bounds of selected areas' frequency (dashed) with simulated deterministic trajectories (solid).

IV. CONCLUSIONS

An innovative five-step design framework has been described to plan 40-year transmission investment portfolios at the national level. The benefits of the national transmission overlays have been demonstrated, in terms of cost, emissions, and dynamic frequency performance. It has been estimated that transmission overlay benefits can range from 324B$ to 568B$ in total cost reduction, and 3.6 to 7.4 billion short tons in CO_2 emission reductions from electric systems. Though not shown here, results also indicate that a transmission overlay enhances resilience to large-scale disturbances and increases flexibility to changing future scenarios. Moreover, we have developed a method for studying dynamics of bulk power systems in the presence of uncertainty. The control capabilities of a new HVDC overlay were shown to be beneficial in terms of improved frequency response

V. FUTURE WORK

A multi-stage transmission investment optimization under-uncertainty, with steady state, and dynamic reliability considerations will be performed. This is computationally challenging, hence two methods have been investigated to solve this problem. The first is to implement a parallel computing platform on a high performance computer at ISU, which has 3200CPUs, 44TB memory and a peak performance of 15.7 TF. The second is to enhance traditional Benders' decomposition algorithm to speed up its convergence rate.

On the dynamics side, we are working towards improving the reachability analysis algorithm, to permit the study of systems described by differential algebraic equations and systems with switching events. The speed-up of the reachability analysis through algorithmic improvements and parallelization might be possible. We also plan to develop more sophisticated models of power system components (e.g., HVDC dynamic models, aggregated wind power plants) and uncertainties associated with the high penetration of renewable sources.

VI. Access to Products

For high resolution plots, detailed transmission investment portfolios and other products, please email: yfli@iastate.edu.

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VIII. Biographies

Yifan Li received the B.S. degree in Electrical Engineering from Xi’an Jiaotong University, China, in 2009. He worked in California Independent System Operator (CAISO) in 2010. He is currently pursuing his Ph.D. in Electrical Engineering with major concentration in Power Systems at Iowa State University, Ames IA. His research interests include transmission system modeling and optimization with high renewable penetration, graph theory applications in power systems and power system economics.

Hugo Villegas received his B.S. in electrical engineering (automation and control) from Escuela Superior Politécnica del Ejército, Ecuador, in 2008. He worked as a supervisor of electrical maintenance in Guangopolo Power Station, Ecuador, from 2007–2009. He was a Fulbright recipient as a Masters student of electrical engineering at Iowa State University, Ames, IA, during 2009–2011. Currently, he is pursuing his Ph.D. in the same university. His research interests include power system analysis and wind energy conversion.

James McCalley received the B.S., M.S., and Ph.D. degrees from the Georgia Institute of Technology, Atlanta, in 1982, 1986, and 1992, respectively. He was employed with the Pacific Gas and Electric Company, San Francisco, CA, from 1985 to 1990 and is currently Harpole Professor of Electrical and Computer Engineering at Iowa State University, where he has been since 1992. Dr. McCalley is a registered Professional Engineer in California and a fellow of the IEEE.

Dionysios Aliprantis received the Diploma in electrical and computer engineering from the National Technical University of Athens, Greece, in 1999, and the Ph.D. from Purdue University, West Lafayette, IN, in 2003. He is currently an Assistant Professor of Electrical and Computer Engineering at Iowa State University. He was a recipient of the NSF CAREER award in 2009. More recently his work has focused on technologies that enable the integration of renewable energy sources in the electric power system, and the electrification of transportation.

Computational Issues of Optimization for Planning (5.2)

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***Abstract*—Increased integration of renewable energy and price-responsiveness of demand impose significant uncertainties on long-term resource planning. Fuel price and intermittent generation uncertainties can be incorporated into planning optimization problems as probabilistic scenarios. Market behaviors can be captured in multi-level leader-follower formulations. Both approaches greatly increase computational complexity relative to deterministic, single-level optimization. This research task has included two complementary thrusts: (1) improving a scenario reduction heuristic for centralized expansion planning, and (2) devising a solution procedure for a tri-level model of decentralized expansion planning. Our scenario reduction heuristic leads to choosing very similar expansion decisions as does a standard scenario reduction method, but the overall computation time for reducing the scenario set and solving the reduced problem is substantially lower. Our hybrid iterative algorithm for the tri-level model finds optimal transmission expansion plans in reasonable computation times when tested on 6-, 30- and 118-bus systems.**

I. Nomenclature

Indices for generation expansion stochastic program:

i	Index for scenarios
t	Index for subperiods in the planning horizon
y	Index of years
g	Index for generator type

Sets for generation expansion stochastic program:

G	The set of generation technology of which the number is limited
Y_t	The year to which the subperiod t belongs

Decision variables in generation expansion stochastic program:

U_{gy}	The number of generators of type g to be built in year y, integer
E_{gti}	Power provided by generator type g in subperiod t under scenario i, MW
UE_{ti}	Unserved energy in subperiod t in scenario i, MWh

Parameters in generation expansion stochastic program:

p_i	The probability that scenario i occurs
b_g	Total cost to build a generator of type g, discounted to beginning of construction period, \$/MWh
fm_g	Fixed O&M cost of generator type g
$m_g^{\max}$	Installed capacity of generator type g, MW
h_t	Total hours in subperiod t
r	Annual interest rate for cost discounting
Pc	Penalty for unserved energy, \$/MWh
n_g	Capacity factor of type g
I_g	The total generation capacity of generators of type g at the beginning of the planning horizon
$u_g^{\max}$	The maximum number of generators of type g to be built over the planning horizon

Scenario related parameters:

c_{gti}	Generation cost for generator type g in year t under scenario i, \$/MWh
d_{ti}	Annual electricity demand in year t under scenario i, MWh

Notation for the FSWC heuristic:

n	Number of scenarios in the reduced set
n_g	Number of initial clusters
$V_Y^{(k)}$	Cumulative number of generators built up to year Y in cluster k
$C^{(k)}$	Composite cost for scenarios in cluster k

Descriptors of the tri-level solution procedure:

z^m	Candidate transmission expansion from the master problem
Ω^m	Generation expansions and all operational decisions found in the master problem
Ω^s	Generation expansions and all operational decisions found in the sub-problem
$F(z,\Omega)$	System net surplus
F^{best}	Lower bound on system net surplus

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II. Introduction

As integration of renewable energy increases and demand becomes more responsive to price, long-term resource planning problem formulations must incorporate increasing levels of uncertainty. In stochastic programming models, uncertainties are expressed in terms of probabilistic scenarios, and decisions are divided into two sets. First stage investment decisions require commitment before the scenario realization is known, while second- or later-stage operational decisions can take recourse depending on which scenario occurs. A full representation of multidimensional uncertainty results in a large number of scenarios and computational intractability. At the same time, considering the market implications of planning decisions requires a multi-level structure where planning decisions in the upper levels anticipate market reactions in a lower level equilibrium among market participants. Such problems also pose computational challenges.

To incorporate uncertainty in the form of scenarios, the main research issue is to derive a smaller set of scenarios that well represent the impacts of uncertain variables on the investment decisions. In previous research, a scenario reduction method termed Forward Selection in Wait-and-See Clusters (FSWC) was developed for medium-term fuel and generation planning problems [8]. This method clusters scenarios based on their impact on first-stage decisions and then applies a widely used forward selection heuristic to select one scenario for retention from each cluster. The clustering procedure must be customized for each application. In this Future Grid project, we have generated the scenario sets for generation expansion planning (GEP) by formulating stochastic models for uncertain variables such as future loads and fuel prices, which are continuous quantities, and then forming discrete scenario trees to approximate their possible evolution paths. We investigated the best set of investment variables and transformations of them on which to cluster the scenarios and performed computational tests to compare this FSWC against forward selection alone. The approach is described in more detail in Section III.A and the results are presented in Section IV.A.

To incorporate the effects of market behaviors on both transmission and generation investments, we formulated and solved a tri-level model of transmission and generation expansion in the context of a restructured wholesale market. The top level represents a centralized transmission planner, the second level depicts the expansion planning decisions of multiple generation companies (gencos), and the third level is an equilibrium model of operational decisions by the gencos and system operator to meet demands of load-serving entities in a wholesale electricity market. We developed a hybrid iterative algorithm that generates promising transmission expansions quickly by applying a complementarity reformulation and evaluates their performance in the lower level subproblems using diagonalization [1]. When tested on 6-, 30- and 118-bus systems, it found optimal transmission expansion plans in reasonable computation times. The model and solution approach are described in Section III.B and highlights of results are reviewed in Section IV.B.

Additional work on stochastic GEP that has been partially supported by this project includes a study of how demand response (DR) can mitigate uncertainties associated with high penetration of wind power [2], and an investigation into the comparative effects on expansion decisions of including granularity in the operational modeling or in the stochastic modeling [3]. Currently, we are extending a bi-level simplification of the tri-level model to include uncertain conditions in the market equilibrium subproblem. These efforts are briefly described in Section V, along with overall conclusions.

III. APPROACH

This section briefly describes (A) the stochastic GEP model, scenario generation, and scenario reduction heuristic [4, 5], and (B) the tri-level model and solution approach [6, 7].

A. Two-Stage Stochastic Program for GEP

A simple two-stage stochastic program for generation expansion planning is formulated as:

Objective function

$$\min_{U_{gy},E_{gti},UE_{ti}} \sum_i p_i \xi_i \tag{1}$$

$$\xi_i = \sum_y \sum_g \left(b_g + fm_g\right) m_g^{\max} U_{gy} \Big/ \left(1+r\right)^{y-1} + \sum_{t\in Y_t} \left(\sum_g c_{gti} E_{gti} + PcUE_{ti}\right) \Big/ \left(1+r\right)^{y-1} \tag{2}$$

Constraints

Limitation on expansion of some generator types:

$$\sum_y U_{gy} \le u_g^{\max} \quad , \forall g \in G \tag{3}$$

Generation capacity:

$$E_{gti} \le h_t \left(n_g m_g^{\max} \sum_{y\le Y_t} U_{gy} + I_g\right) \ , \forall g,t,i \tag{4}$$

Energy balance:

$$h_t \sum_g E_{gti} + UE_{ti} = d_{ti} \ , \ \forall t,i \tag{5}$$

Nonnegativity:

$$U_{gy}, E_{gti}, UE_{ti} \ge 0 \ , \ \forall g,y,t,i \tag{6}$$

The objective function (1) – (6) indicates the purpose of identifying an expansion and generation plan that achieves the minimum expected cost over all possible scenarios. The expected discounted cost includes investment cost, generation (including maintenance) cost and penalty cost from unserved energy over the whole planning horizon. The investment decisions, U_{gy}, are the first-stage decision variables, while E_{gti} and UE_{ti} are second-stage decisions that depend on the scenario realization. Due to financial capacity, environmental impacts, reliability of power system and other drivers, the total number of some types of generators to be built tends to be bounded, as formulated in (3). Constraint (4) represents capacity constraints of existing and new generators. Constraint (5) determines the unserved energy in each scenario as the difference between the electricity demand and the total energy provided by generators in each time period. Here, the demand for electricity and the generation costs are random variables, with realizations d_{ti} and k_{gti} for generator type *g*, respectively, in year *t* and scenario *i*. For cost, we focus on uncertainty in the price of natural gas.

Two scenario trees were generated by a moment-matching method [9] with three branches from each node; thus, each tree has 3^{10} scenario paths. In the first tree, time periods increase in length over a 20-year horizon. The second tree has equal length periods and a two-dimensional lattice structure with respect to demand.

Because the computational effort to solve a stochastic program depends heavily on the number of scenarios used, we developed a method to reduce that number without sacrificing accuracy of the solution. A widely used method for scenario reduction is **fast forward selection (FFS)** [10]. The FFS heuristic approximates the scenario probability distribution with a set of scenarios of specified smaller cardinality. We employ this algorithm within clusters of scenarios in our scenario reduction heuristic, termed **Forward Selection in Wait-and-See Clusters (FSWC)**. The FSWC method clusters scenarios based on their impact on key first-stage decisions, then applies forward selection within each scenario cluster [4]. The steps are [5]:

Step I: Set the cardinality of the reduced scenario set to n, solve the deterministic wait-and-see problem based on each scenario, and retain the values of the first-stage variables (expansion strategies, U_{gy});

Step II:

1. Group the original scenarios into the same cluster if their first-stage decisions are the same; if the number of clusters n_G is less than or equal to n then go to Step IV. Otherwise, for each cluster $k=1,\ldots,n_G$:
2. Calculate the cumulative number of built generators $V_Y^{(k)}=\sum_{y=1}^{Y}U_{gy}^{(k)}$, and total capacity of each type of generator in each year; form a row vector $V^{(k)}=[n_g^{\max}\times V_Y^{(k)}]_{1\times N}$ for each expansion strategy, where $N=|g|\times|y|$;
3. For each scenario $i=1,\ldots,r^{(k)}$, calculate the investment, generation cost and penalty given that cluster's expansion strategy, and form a cost vector for the strategy. Assume the probabilities of scenarios that result in the same expansion strategy are $P^{(k)}=[p_1^{(k)},p_2^{(k)},\cdots,p_{r^{(k)}}^{(k)}]$. The investments, generation costs and penalties form a matrix $F^{(k)}=[inv_i,gen_i,penalty_i]_{r^{(k)}\times 3}$, and then the cost vector for the strategy is obtained by $C^{(k)}=P^{(k)}\times F^{(k)}\Big/\sum_{i=1}^{r^{(k)}}p_i^{(k)}$;
4. Combine the obtained two vectors in 2 and 3 into a vector $[V^{(k)},C^{(k)}]$, and normalize $V^{(k)}$ and $C^{(k)}$ to have similar magnitudes.

Step III: Cluster the n_G groups of key first-stage decisions into n clusters by applying the k-means method under the l^2-norm to their corresponding vectors $[V^{(k)},C^{(k)}]$, and form the corresponding n clusters of original scenarios at the same time;

Step IV: Apply the FS method to select one scenario from each cluster of the original scenarios.

B. A Tri-level Transmission and Generation Expansion Model

Sufficient generation expansion is essential to an electricity network with constantly growing load. However, in restructured electricity markets, it is each genco's decision to expand generation capacity. In a competitive market, the primary goal for each genco is profit. It is interesting to investigate the strategic decisions of each genco, the interaction among them, and the market behavior that results. Because the gencos' expansion decisions are affected by the transmission grid, in our model the top level represents discrete centralized transmission expansion decisions by the ISO with anticipation of the expansion decisions made by its followers, the gencos. In the second level, each genco makes its own generation expansion planning decision subject to constraints derived from an electricity market equilibrium problem in the third level where the gencos, a conceptual fuel dispatcher and the ISO simultaneously optimize their own operational benefits on an hourly basis. In this third-level Cournot competition model, each genco decides its generation level, the ISO matches generation with loads to maximize the total social welfare and the fuel dispatcher minimizes the total fuel cost including delivery. The problem is formulated as a static tri-level model with the ISO's discrete transmission expansion decisions on the first level, multi-gencos' separate generation expansion decisions on the second level, and multiple market players' operational decisions in the third level. Figure 1 depicts the three levels of decision-making.

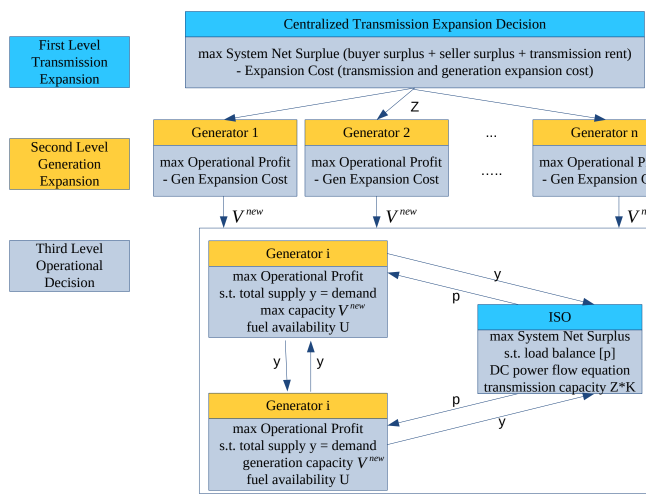

Fig. 1. A Tri-level Integrated Generation and Transmission Expansion Planning Model

The bi-level equilibrium sub-problem in the tri-level model involves multi-gencos' generation expansion decisions in the upper level and a market equilibrium in the lower level. Each genco solves a bilevel problem with a convex lower level problem, which can be reformulated easily as an equivalent mathematical program with equilibrium constraints (MPEC). Combining these for the multiple gencos in our model, we obtain an equilibrium program with equilibrium constraints (EPEC). In the complementarity problem (CP) reformulation, the necessary conditions for optimality of each MPEC are combined to reformulate the EPEC as a mixed complementarity problem. Due to lack of convexity of the MPECs, solving this CP reformulation provides only necessary conditions for an equilibrium solution of the original bi-level game, but not a sufficient condition. With the CP reformulation, the tri-level problem can be converted into a single level optimization problem including sets of nonlinear, linear and complementarity constraints. This problem is a generalized MPEC that can be reformulated for solution by commercial codes.

The two currently available algorithms to solve a bi-level game as an EPEC are the diagonalization method (DM) and CP reformulation. Based on previous studies, given a certain transmission expansion planning decision, the performance of DM is quite stable in successfully identifying a Nash equilibrium of the bilevel game; while CP reformulation can only provide a bound on the optimal value. However, the advantage of the CP reformulation is that it can solve the entire tri-level problem at once. We developed a hybrid iterative algorithm that takes advantage of both approaches by first applying the CP reformulation as a relaxation to identify promising transmission expansion decisions to start with and further using DM to find a Nash equilibrium point of the bi-level game [6]. The hybrid algorithm uses a decomposition approach. The master problem, solved in major iterations, is a mixed-integer nonlinear programming (MINLP) reformulation of the trilevel problem. Equilibrium bi-level subproblems (EPECs) are solved in minor iterations for each candidate transmission expansion solution. Figure 2 illustrates the solution procedure.

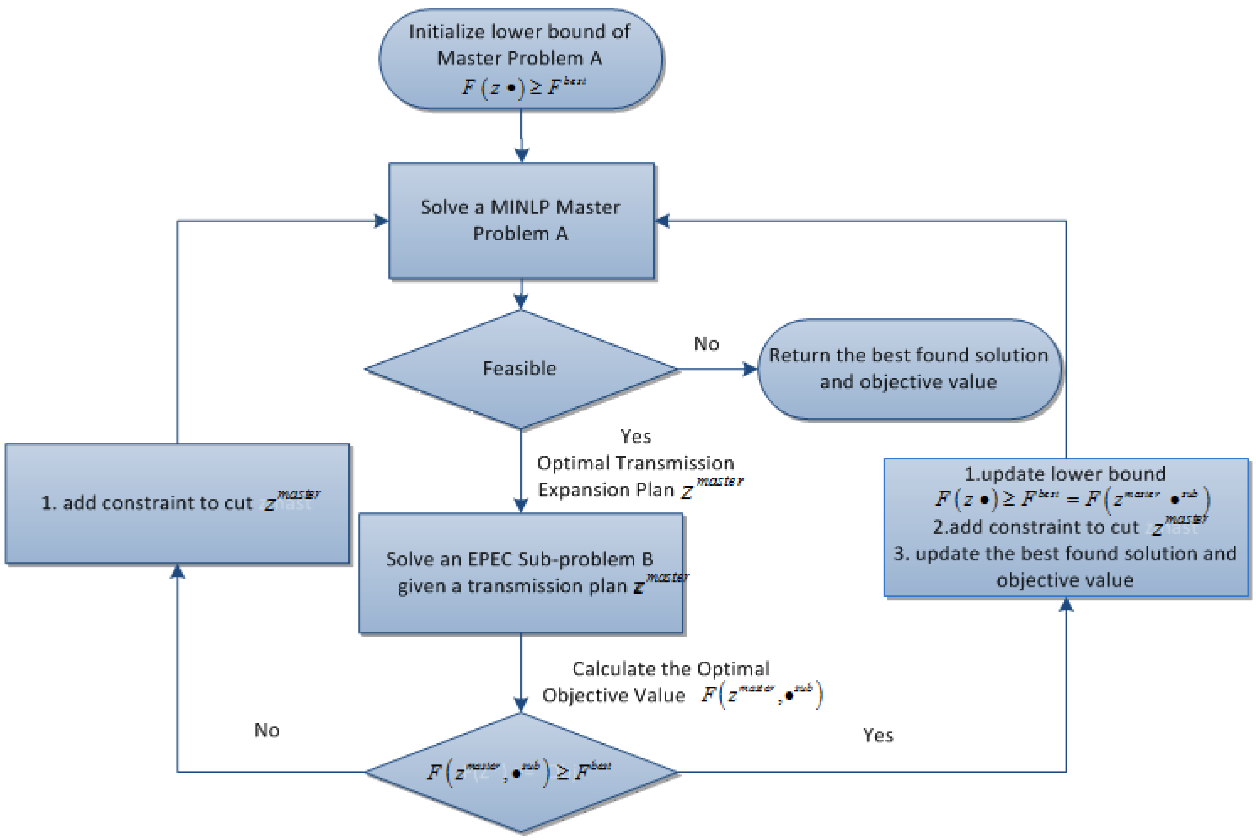

Fig. 2. Hybrid iterative algorithm for the tri-level model.

IV. Results

Results of applying the FSWC scenario reduction heuristic in a case study of GEP are presented in subsection A. Results of solving the tri-level model for a transmission expansion plan appear in subsection B.

A. FSWC in Two-stage Stochastic Program for GEP

We implemented the GEP model (1) – (6), on a hypothetical system based on the US Midwest involving six types of generators over a 20 year horizon. The generator types include base-load (coal), gas combined cycle, gas combustion turbine, nuclear, wind (farm) and integrated gasification combined cycle. Parameter settings are given in [5]. The scenario reduction procedures and stochastic programming solution process were implemented by using Matlab and CPLEX with the interface provided by Tomlab on computers with 3GHz CPU.

Tables I and II summarize the investment cost, generation cost and penalty for unmet energy for model (1) – (6) based on scenarios selected by the two reduction methods, respectively, and also illustrate the performance of the expansion strategies with respect to the original scenarios. The FSWC method provides results similar to or even better than FS in every cost category. Because any unserved energy is penalized by 10^7 \$/MWh, the penalties in expected cost with respect to all scenarios indicate that only a small amount of demand is unsatisfied over the planning horizon. FSWC requires computational times ranging from 31% of that for FS when selecting 30 scenarios to about 11% when selecting 100 scenarios. But it results in very similar first-stage decisions and lower expected costs with respect to the original scenario sets in most cases. Moreover, the time required for FSWC is approximately constant over different reduced set cardinalities.

TABLE I
EXPECTED COSTS AND SOLUTION TIMES BASED ON FS METHOD

Number of selected scenarios		30	40	50	100
Expected cost with respect to selected scenarios ($Billion)	Investment cost	101.46	100.26	100.29	99.42
	Generation cost	81.43	81.37	81.18	81.51
	Penalty	0	0	0	0
	Total cost	182.89	181.63	181.47	180.39
Expected cost with respect to all scenarios ($Billion)	Investment cost	101.46	100.26	100.29	99.42
	Generation cost	79.58	80.60	80.51	81.31
	Penalty	70.86	69.36	69.69	43.88
	Total cost	251.90	250.22	250.49	224.61
Scenario reduction time (CPU s)		352,706	442,369	560,907	1,066,800
Sol. time with reduced scenarios(CPU s)		1312	2844	541	1672
Total time pruning and solution (CPU s)		354,018	445,213	561,448	1,068,472

TABLE II
EXPECTED COSTS AND SOLUTION TIMES BASED ON FSWC METHOD

Number of selected scenarios		30	40	50	100
Expected cost with respect to selected scenarios ($Billion)	Investment cost	98.88	99.99	99.09	99.61
	Generation cost	81.22	81.28	81.57	80.92
	Penalty	0	0	0	0
	Total cost	181.10	181.27	180.66	180.53
Expected cost with respect to all scenarios ($Billion)	Investment cost	98.88	99.99	99.09	99.61
	Generation cost	82.42	82.15	82.13	81.53
	Penalty	19.82	14.96	19.79	72.59
	Total cost	201.22	197.10	201.10	253.73
Scenario reduction time (CPU s)	Solve scenario probs	90,460	90,460	90,460	90,460
	Cluster	20,129	20,129	20,129	20,129
	Select	638	525	412	290
Solution time with reduced scenarios(CPU s)		135	244	699	1534
Total time pruning and solution (CPU s)		111,362	111,358	111,760	112,413

B. Tri-level Transmission and Generation Expansion

The hybrid iterative algorithm was successfully tested on a modified IEEE 30 bus system with 6 generators on 6 different buses, 39 existing transmission lines and 10 candidate transmission lines, labeled as A, B, …, J [7]. The total number of all transmission expansion options is 2^{10}, which makes solving by enumeration impractical. The hybrid algorithm uses a decomposition approach. The procedure solves the 30-bus problem within 5 major iterations and a total computation time of 5591.97 seconds. The iterative results are summarized in Table III. In the fourth major iteration the algorithm finds the optimal solution, which is to build only candidate line H. This result also appears to be consistent with the case study results on a similar system found in [11].

TABLE III
RESULTS ON MODIFIED IEEE 30 BUS TEST SYSTEM

Iteration	Master Problem			Sub-problem	Bound
	Status	z^m	$F(z^m,\Omega^m)$	$F(z^m,\Omega^s)$	F^{best}
1	Feas	None	13235.34	13038.62	13038.62
2	Feas	B	13057.90	12727.90	13038.62
3	Feas	E	13216.10	12957.11	13038.62
4	**Feas**	**H**	**13246.07**	**13066.56**	**13066.56**
5	Inf.				

The algorithm was also tested on a standard IEEE 118 bus system with 54 generators, 179 existing lines and 4 candidate lines. The candidate lines were selected as likely to help relieve the congestion in the existing system. The algorithm identified the best solution at the first major iteration and found two more feasible, though inferior, solutions in the second and third rounds. We also obtained the global optimal solution of the 118 bus case study by enumerating all the 16 possible transmission expansion options, and verified that the best solution found by the algorithm turned out to be globally optimal in this instance.

V. CONCLUSIONS AND FUTURE WORK

The goal of this task has been to develop improved computational methods for long-term resource planning under uncertainty. Efforts have focused on two complementary thrusts:

1. Further develop, implement and test a method to reduce the number of scenarios considered in stochastic programming when implemented with a rolling time horizon.
2. Solve multiple variations of a bi-level optimization problem with uncertainty in the lower-level market equilibrium sub-problem.

The first research thrust has focused on a two-stage stochastic programming formulation of generation expansion planning to minimize investment and operational costs over a long time horizon, with uncertainties in demand and fuel price. We developed methods to generate scenario trees based on stochastic process models of the uncertain variables for different subdivisions of the study horizon, as well as a customization of a new scenario reduction heuristic to thin the scenario trees and account for risk. The major result is a demonstration that our new scenario reduction heuristic leads to choosing very similar expansion decisions as does a standard scenario reduction method, but the overall computation time for reducing the scenario set and solving the reduced problem is substantially lower.

Two related studies of generation expansion using stochastic programming were partially supported by this project. The first focused on the impact of demand response (DR) on investment in thermal generation units at high wind penetration levels [2]. The investment model combined continuous operational constraints and wind uncertainties to represent the implications of wind variability and uncertainty at the operational level. DR was represented in terms of linear price-responsive demand functions. A numerical case study based on the real load and wind profile of Illinois was constructed with 20 candidate generating units of various types. Numerical results showed the impact of DR on both investment and operational decisions. An alternative model in which DR provides operating reserves was also proposed to discuss DR's impact on lowering the total capacity needed in the system. We observed that a relatively small amount of DR capacity could be sufficient to enhance the system reliability with lower reserve/wind curtailment and improve both the social surplus and generator efficiency with higher capacity factors compared to the case with no demand response. The second related study involved a stochastic generation expansion model, where we represented the long-term uncertainty in the availability and variability in the weekly wind pattern with multiple scenarios [3]. Scenario reduction was conducted to select a representative set of scenarios for the long-term wind power uncertainty. We assumed that the short-term wind forecast error would induce an additional amount of operating reserves as a predefined fraction of the wind power forecast level. Unit commitment (UC) decisions and constraints for thermal units were incorporated into the expansion model to better capture the impact of wind variability on the operation of the system. To reduce computational complexity, we also considered a simplified economic dispatch (ED) based model with ramping constraints as an alternative to the UC formulation. We found that the differences in optimal expansion decisions between the UC and ED formulations were relatively small. We also concluded that the reduced set of scenarios could adequately represent the long-term wind power uncertainty in the expansion problem. The case studies were based on load and wind power data from the state of Illinois.

The second research thrust has expanded the proposed bi-level optimization problem to a tri-level model of transmission and generation expansion in the context of a restructured wholesale market. The top level represents a centralized transmission planner, the second level depicts the expansion planning decisions of multiple gencos, and the third level is an equilibrium model of operational decisions by the gencos and system operator to meet demands of load-serving entities in a wholesale electricity market. We developed a hybrid iterative algorithm that generates promising transmission expansions quickly by applying a complementarity reformulation and evaluates their performance in the lower level subproblems using diagonalization. When tested on 6-, 30- and 118-bus systems, it found optimal transmission expansion plans in reasonable computation times.

A limitation of the bi-level and tri-level implementations to date is that the market equilibrium problem is solved only for a single scenario, which represents a particular configuration of energy supply and demand in a future hour. In reality, resource expansions must be made in anticipation of a wide range of future operating conditions over a long time horizon. In on-going work, we are expanding a bi-level formulation to reconcile the long-term and discrete nature of generation and transmission expansion decisions with their steady-state operational effects in a short-term market environment. In this formulation, a collection of lower level equilibrium sub-problems simulates daily or hourly market operations with multiple decision-makers. Intermittent generation from renewable sources such as wind or solar units combines with uncertain demand, system contingencies and volatile fuel prices to create significant stochasticity in the lower level. The research challenges are to generate representative scenarios and then solve the much-expanded discrete optimization problem. We expect that the FSWC scenario reduction approach will assist in making the computation tractable.

VI. Project Publications to Date

[1] S. Jin, "Electricity system expansion studies to consider uncertainties and interactions in restructured markets," Ph.D. dissertation, Dept. Ind. & Mfg. Sys. Eng., Iowa State Univ., Ames, 2012.

[2] S. Jin, A. Botterud, and S. M. Ryan, "Impact of demand response on thermal generation investment with high wind penetration," *IEEE Trans. Smart Grid*, under review.

[3] S. Jin, A. Botterud, and S. M. Ryan, "Temporal vs. stochastic granularity in thermal generation capacity planning with wind power," *IEEE Trans. Power Systems*, under review.

[4] Y. Feng and S. M. Ryan, "Scenario construction and reduction applied to stochastic power generation expansion planning," *Computers and Operations Research*, vol. 40, pp. 9-23, 2013.

[5] Y. Feng and S. M. Ryan, "Application of scenario reduction to LDC and risk based generation expansion planning, in *Proc. 2012 IEEE Power & Energy Society General Meeting*.

[6] Jin, S. and S. M. Ryan, "A tri-level model of centralized transmission and decentralized generation expansion planning for an electricity market: Part I," *IEEE Trans. Power Systems*, under revision.

[7] Jin, S. and S. M. Ryan, "A tri-level model of centralized transmission and decentralized generation expansion planning for an electricity market: Part II," *IEEE Trans. Power Systems*, under revision.

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VIII. Biographies

Sarah M. Ryan received her Ph.D. degree from The University of Michigan, Ann Arbor. She is currently Professor in the Department of Industrial and Manufacturing Systems Engineering at Iowa State University. Her research applies stochastic modeling and optimization to the planning and operation of service and manufacturing systems.

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Integrating Transmission and Distribution Engineering Eventualities (1.1)

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Abstract—This is a report summarizing findings for Task 1.1 of the PSERC / DOE initiative on the future grid. The main topical coverage in this report is transmission engineering. The topics addressed are innovative high voltage DC (HVDC) technologies; and innovative overhead transmission technologies. Key elements of the results relate to multiterminal HVDC systems, networked HVDC, high temperature low sag (HTLS) overhead transmission, phase compaction, and high phase order. Relating to HVDC, an illustration of expansion of the Pacific DC intertie is described. Relating to HTLS, a summary of the main application areas for upgrading is presented – and these are mainly for thermally limited critical paths. The results of high phase order include the underpinnings of transmission theory for these systems.

I. Introduction

THIS is a report on Thrust 1.1 of the PSERC DOE initiative on the future grid. The objectives of this thrust are to:

- Maximize the utilization conductor and insulating systems in overhead and underground transmission
- Maximize space utilization
- Maximize use of investment in transmission assets / designing a favorable cost-benefit ratio
- Permit solutions to transmission problems that have few viable alternatives
- Alleviate critical transmission paths
- Design new asynchronous connections for specialized applications.

In order to address these objectives, the following main research areas were considered:

- High voltage DC systems, including multiterminal and networked designs.
- High temperature low sag overhead conductor applications
- Phase compaction for overhead transmission
- Six phase and higher phase order for overhead and cable transmission engineering.

Relating to fundamental overhead and underground transmission, a wide range of eventual technologies is studied. These include ultra high voltage (e.g., > 1000 kV); six phase transmission and related polyphase designs; high voltage DC (including expansion of existing facilities, routing of circuits in Mexico, multiterminal DC, and meshed DC systems); and variable frequency concepts. The new advances in high temperature low sag overhead conductors, and compact overhead designs appear to yield from 100% to nearly 200% improvement in transmission characteristics. It is possible that the main element in future systems with high levels of renewables shall be the study, development, and ultimate implementation of high levels of energy storage.

The work described in this paper was made possible by funding provided by the U.S. Department of Energy for "The Future Grid to Enable Sustainable Energy Systems," an initiative of the Power Systems Engineering Research Center. The authors may be reached at {heydt, brian.pierre}@asu.edu

A. HVDC Technologies

HVDC systems are considered through the innovative use of multiterminal and networked systems. The research used as a test bed some portions of the southwest US / Western Electricity Coordinating Council system (e.g., Fig. 1). Motivation for examination of these technologies include: paucity of viable rights-of-way for added transmission paths; expected added generation resources far from load centers (e.g., renewable resources such as wind and solar); continued improvement in system reliability by employing asynchronous connections of large interconnection areas. Table I shows a brief listing of advantages of some HVDC technologies.

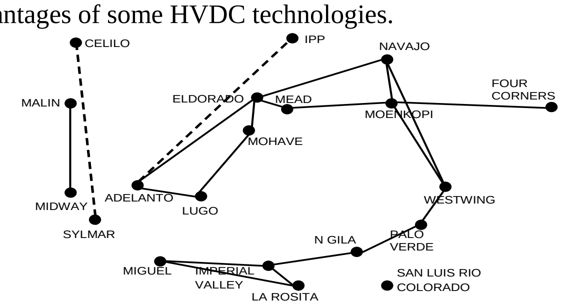


Fig. 1. Stylized, simplified southern portion of the Western interconnection in North America. Dotted lines are existing HVDC lines. Solid lines are AC. Note that San Luis Rio Colorado and La Rosita are in Mexico. The PDCI is shown dotted (Celilo – Sylmar).

TABLE I
ADVANTAGES OF HVDC TECHNOLOGIES
AND REPRESENTATIVE DOCUMENTATION OF CAPABILITIES‡

Area	*Advantage*
Bulk energy transport	Lower active power losses
	Lower right of way cost for a given power level
Synchronous attributes	Asynchronous tie, increased available transfer capability
	Ability to be switched at electronic speeds
	Ability to be modulated for favorable dynamic stability response
Cost	Lower transmission conductor / tower / right of way costs*

‡Advantages abstracted from [1-7]
*A main disadvantage, however, is the higher cost of converter stations for AC interface

B. HTLS and Phase Compaction

HTLS and phase compaction were also considered as an innovative concept for bulk transmission. The main purpose of high temperature low sag conductors is to improve the thermal rating of a transmission line. A typical HTLS conductor can accommodate 1.6 to 3 times the current of a similar conventional conductor. This increase in current is proportional to the increase in thermal rating. However, this increase in current comes at a dollar cost of up to 6.5 times that of a conventional conductor (see Table II). Comparing the alternatives of a single HTLS circuit versus a *double circuit* conventional line, HTLS may have higher I^2R losses as a consequence of the higher current and slightly higher resistance. HTLS conductor operating temperatures can be in the range 80^o to 250^o C, and consequently the conductor resistance can be higher than that seen for conventional conductors.

TABLE II
CURRENT RATINGS AND COMPARATIVE COST FOR HTLS CONDUCTOR

Conductor type	Relative ampacity*	Relative cost*	Manufacturer‡
ACCC	2.0	2.5-3.0	CTC Cable
ACCR	2.0-3.0	5.0-6.5	3M
ACSR	1.6-2.0	2.0	J-Power
ACSS/TW	1.8-2.0	1.2-1.5	Southwire
ACSS/AW	1.8-2.0	1.2-1.5	Southwire
ACIR/AW	2.0	3.0-5.0	LS Cable

*Compared to conventional conductors of similar cross-section, for typical commercially available HTLS conductors ‡Representative data from [9]

Phase compaction refers to spatially designing phase conductors closer than usual contemporary designs. The basic impulse level dictates the ultimate limit in phase spacing. Note that as phase spacing decreases, the mutual coupling between phases increases, the positive sequence reactance of the line decreases, and therefore the security limit power rating of the line increases.

C. High Phase Order

Three phase technologies have generally been the design of choice since the inception of electric power systems. In this thrust area, the prospect of six-phase and higher phase order were also studied. The main result areas relate to spatial utilization, high transmission capacity, the impact of untransposed systems, and the potential for high phase order underground cables.

II. HIGH VOLTAGE DC TRANSMISSION

The Western interconnection in North America contains many examples of potential applications for HVDC technologies, both in the milieu of long, bulk energy transport and in asynchronous ties. By no means is the Western interconnection unique in this regard, but it does serve as a valuable test bed for applications. A stylized, simplified portion of the Southern California – Arizona part of the Western interconnection is shown in Fig. 1. One of the best known HVDC systems is the Pacific HVDC Intertie (PDCI) which spans Celilo, Oregon to Sylmar, California, a total distance of about 1354 km. The history and development of this 3.1 GW, ±500 kV bipolar system is documented by [10]. The PDCI takes advantage of the different seasonal load peaks between the Northwest and Southwest of the U.S. and therefore helps to exchange energy between the two regions. However, because Sylmar converter station is located near Los Angeles area which is considered as a significant load center, and because of the excess in hydro power generation in Northwest, the flow of power is mostly from north to south.

The PDCI has gone through several changes since it was commissioned in 1970 until it reached its present configuration. These changes happened in response to two earthquakes, a fire, and environmental and economical considerations. New converters were added and mercury arc 'valves' were replaced with thyristors which raised the PDCI ratings from ±400 kV, 1800 A and 1440 MW to ±500 kV, 3100 A and 3100 MW. Additional application areas for HVDC transmission are in underground high voltage systems and in submarine applications. There are many locations in North America where heavy load centers are centrally located in a densely developed business district surrounded by highways, residential areas, and geographical features. Examples of potential submarine HVDC transmission applications exist on the Atlantic and Pacific coasts of North America (the Long Island NY – Neptune NJ project, 105 km, 600 MW; and the Transbay Project in San Francisco CA, 95 km, 400 MW).

To illustrate a meshed HVDC application, consider Fig. 2 [11]. It should be stated that this is just an illustration of a meshed HVDC connection: no actual implementation is implied or proposed. Table III shows the results of a typical operating condition for the indicated meshed HVDC network. In order to examine the steady state operation of the meshed HVDC example, both the WECC and northwest region of Mexico interconnections were represented as two separate AC islands that are coupled by the HVDC ties shown in Fig. 2. Power injection at each converter station was set according to an assumed scenario that represents the first phase of this meshed HVDC interconnection example. Table IV shows the power injection at the converter stations as well as the line flows. Losses are not included in this particular study.

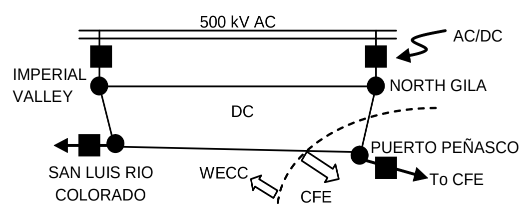


Fig. 2. Simplified schematic of a meshed HVDC network joining WECC and mainland CFE (Mexico)

The steady state study also examined the reliability of the suggested meshed HVDC interconnection. A fault on a single pole at any converter station would cause that converter to operate in monopolar mode instead of de-energizing the whole converter. Furthermore, if the entire HVDC tie between two converter stations was lost, the suggested configuration allows power to flow to all four nodes without interruption. On the other hand, the HVDC tie line between North Gila and Imperial Valley would also alleviate congestion in the existing 500 kV AC line which is a highly loaded major transmission line between Arizona and California. Power injection at converter stations can be increased in future phases by upgrading the converters to accommodate future needs.

III. HTLS AND PHASE COMPACTION

Consideration now turns to the dynamic response of systems with overhead transmission for the cases of reconductoring with HTLS and / or compact phase spacing. Short lines are generally thermally limited, and short lines that are critical paths are perhaps the best candidate for upgrade using HTLS. However, to illustrate the *dynamic* consequences of reconductoring, consider a long line as a test bed. The Bridger West critical path is such a line and this is illustrated in Fig. 3. Note the series compensated segment of the Bridger –Three Mile Knoll line.

TABLE III
MESHED HVDC ILLUSTRATION IN WECC

Converter stations				
Station	Interconnection region	Technology	Voltage rating	Control type
North Gila, AZ	WECC	VSC	±500 kV	Current
Imperial Valley, CA	WECC			Voltage
San Luís RC, Sonora	WECC			Current
Puerto Peñasco, Sonora	CFE			Current
HVDC transmission				
Length (km)	North Gila – Imperial Valley: 114		Imperial Valley – San Luis RC: 96	
	San Luis RC – Puerto Peñasco: 170		Puerto Peñasco – North Gila: 181	
Conductor	Falcon (1590 kcmil)			
Conductor/ pole	2			
Voltage rating	± 500 kV			
Power rating*	2.63 GW			

* Maximum for the indicated conductor

TABLE IV
POWER INJECTION AND LINE FLOWS
IN A MESHED HVDC SYSTEM

Converter station	
Station	Power injection MW
North Gila, AZ	600
Imperial Valley, CA	-470*
San Luís RC, Sonora	-300*
Puerto Peñasco, Sonora	170
HVDC lines	
Line	Line flows MW
North Gila – Imperial Valley	506
Imperial Valley – San Luís RC	36
Puerto Peñasco – San Luís RC	264
North Gila – Puerto Peñasco	94

* Negative sign indicates power flow direction from the DC to AC network

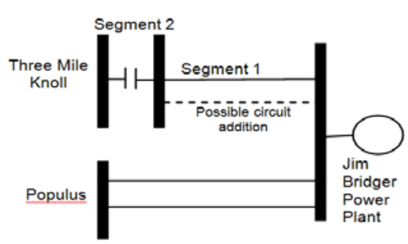


Fig. 3. Pictorial of the Bridger – West critical path in Idaho and Wyoming

Consider three cases in which alteration of the present design occurs in the Bridger to Three Mile Knoll 345 kV circuit. This is one of three critical circuits from the Jim Bridger power plant, and this circuit is series compensated. The three cases considered are: (1) present construction; (2) HTLS plus compaction of spacing by 25%; and (3) HTLS plus compaction to 50% spacing as compared to the original design *plus* the addition of a new Bridger – Three Mile Knoll circuit as shown in Fig. 3. In Case 3, it is assumed that the use of HTLS allows the compaction of the phase spacing so that the original right of way need not be widened. For purposes of evaluating the dynamic response, two double line outage contingencies are studied. The two double line outage contingencies are: Bridger to Three Mile Knoll 345 kV plus Bridger to Populus (1); and Bridger to Three Mile Knoll 345 kV plus Bridger to Populus (2).

The cases studied have an actual power transfer along this critical WECC path of 1181 MW from East to West. The cases studied are for the 2020 summer peak load condition. In these cases, the calculated transfer limit along the Bridger West critical path is 2200 MW from East to West. This critical path is studied using the Positive Sequence Load Flow (PSLF) and TSAT analysis packages, commercially available software tools in common use in the electric power industry today. The case study results are shown in Table V. Note that in the results shown in Table V do not include the actions of remedial action schemes (RASs).

TABLE V
DYNAMIC STUDIES FOR DOUBLE LINE OUTAGE CONTINGENCIES (BRIDGER WEST CRITICAL PATH)

Case**		Case 1: present construction	Case 2: HTLS* reconductoring + compact phase spacing by 25%	Case 3: HTLS + compact phase spacing to 50% plus new circuit addition
Double line outage contingency #1	Limitation	Transient voltage dips / voltage magnitude stability	Transient voltage dips / voltage magnitude stability	Transient voltage dips / voltage magnitude stability
	TSAT solution	Bus voltage oscillations: 0.93 Hz mode damped at -2.9%; 1.67 Hz mode damped at -5.5%	Bus voltage oscillations: 0.93 Hz mode damped at -2.9%; 1.67 Hz mode damped at -5.5%	Bus voltage oscillations: 0.93 Hz mode damped at -3.14%; 1.67 Hz mode damped at -6.28%

*Note that the HTLS construction does not materially modify the circuit reactances, and therefore the dynamic response is about the same as for the present construction. **The contingency #2 gives the same results as contingency #1

For this circuit, a triple modular redundant programmable logic controller is used to obtain a generator trip or capacitor insert / bypass signal. These control actions would obviate the instability and poor damping shown in Table V. Because the RASs are not implemented in the TSAT and PSLF simulations, the problematic conditions shown in the table occur. The purpose of the RASs in this application is to make the circuit IEC 61131-3 compliant. Note that the two double line outage contingencies are nearly identical because the circuit reactances outaged are very similar. Inspection of Table V shows that two critical modes that occur during a line outage contingency are better damped in Case 3. It appears that the advantages of Case 3 are that the damping of critical modes is enhanced and the addition of a new 345 kV circuit can be accomplished without widening the existing right of way.

IV. HIGH PHASE ORDER TECHNOLOGIES

Since the inception of AC transmission engineering, three-phase circuits have been the dominant technology. However, six-phase and higher phase order designs have been considered. Test circuits have been constructed and reported [12]. A number of basic properties and design considerations have been reported [13, 14]. It is a simple consequence of trigonometry that when AC phasors in the polyphase case (with n_φ phases) balanced supply voltages will be spaced at $360/n_\varphi$ degrees, and if the line-neutral voltage is taken as a benchmark ($|V_{ln}| = 1$), the law of cosines gives the line to line voltage magnitude as

$$|V_{ll}| = \sqrt{2\left(1 - \cos\left(\frac{360}{n_\varphi}\right)\right)}.$$

Thus as the phase order increases, the line-line voltage magnitude decreases. At very high phase order, again for $|V_{ln}| = 1$,

$$|V_{ll}| \approx \frac{2\pi}{n_\varphi}.$$

A. Transmission System Model

High phase order transmission systems have models that closely parallel the familiar three-phase case. For example, consider a line reactance matrix X_{line} which models the voltage on the n phases of a polyphase line when current I flows in the line (I and V are n-vectors, shown here for the six phase case with all the phases arranged in a circle),

$$V = X_{6\varphi} I = \begin{bmatrix} S & M_1 & M_2 & M_3 & M_2 & M_1 \\ M_1 & S & M_1 & M_2 & M_3 & M_2 \\ M_2 & M_1 & S & M_1 & M_2 & M_3 \\ M_3 & M_2 & M_1 & S & M_1 & M_2 \\ M_2 & M_3 & M_2 & M_1 & S & M_1 \\ M_1 & M_2 & M_3 & M_2 & M_1 & S \end{bmatrix} I. \quad (1)$$

The $X_{n\varphi}$ matrix will always be a Toeplitz circulant matrix [15]. That is, in (1), the self reactances S are equal among the phases, and the mutual terms M_i occur in bands above and below the principal diagonal. For Toeplitz circulant matrices, the eigenvalues and eigenvectors are readily expressed in terms of the S and M_i terms. A circulant matrix has a unique property that *all* circulant matrices of size nxn share the same n eigenvectors, μ_m, $m = 0, 1, \ldots, n-1$, [16],

$$\mu_m = \frac{1}{\sqrt{n}}\left[e^0, e^{-\frac{j2\pi m}{n}}, \ldots, e^{-\frac{j2\pi m(n-1)}{n}}\right]^t. \quad (2)$$

These n eigenvectors can be arranged in columns to form a modal matrix T to diagonalize $X_{n\varphi}$,

$$X_{seq} = T^{-1} X_{n\varphi} T. \quad (3)$$

The diagonal elements of X_{seq} are the eigenvalues of $X_{n\varphi}$. The eigenvalues of $X_{n\varphi}$ are calculated using a property of Toeplitz circulant matrices,

$$\lambda_m = \sum_{k=0}^{n-1} X_{n\varphi,1,k} e^{-j2\pi mk/n}, \quad (4)$$

where $X_{n\varphi,1,k}$ is the $k,1$ entry of the $X_{n\varphi}$ matrix, m is the m^{th} eigenvalue, and n is the number of phases. For example, for $n = 6$,

$$X_{6\varphi} = T_6 X_{6\varphi} T_6^{-1} = diag\begin{bmatrix} 2M_1 + 2M_2 + M_3 + S \\ M_1 - M_2 - M_3 + S \\ -M_1 - M_2 + M_3 + S \\ -2M_1 + 2M_2 - M_3 + S \\ -M_1 - M_2 + M_3 + S \\ M_1 - M_2 - M_3 + S \end{bmatrix}$$

and for $n = 12$,

$$X_{12seq} = T_{12} X_{12\varphi} T_{12}^{-1} = diag\begin{bmatrix} 2M_1 + 2M_2 + 2M_3 + 2M_4 + 2M_5 + M_6 + S \\ \sqrt{3}M_1 + M_2 - M_4 - \sqrt{3}M_5 - M_6 + S \\ M_1 - M_2 - 2M_3 - M_4 + M_5 + M_6 + S \\ -2M_1 + 2M_4 - 2M_5 - M_6 + S \\ -M_1 - M_2 + 2M_3 - M_4 - M_5 + M_6 + S \\ -\sqrt{3}M_1 + M_2 - M_4 + \sqrt{3}M_5 - M_6 + S \\ -2M_1 + 2M_2 - 2M_3 + 2M_4 - 2M_5 + M_6 + S \\ -\sqrt{3}M_1 + M_2 - M_4 + \sqrt{3}M_5 - M_6 + S \\ -M_1 - M_2 + 2M_3 - M_4 - M_5 + M_6 + S \\ -2M_2 + 2M_4 - M_6 + S \\ M_1 - M_2 - 2M_3 - M_4 + M_5 + M_6 + S \\ \sqrt{3}M_1 + M_2 - M_4 - \sqrt{3}M_5 - M_6 + S \end{bmatrix}.$$

The main observation from these calculations are:

- For high phase order, the 'positive sequence' reactance (i.e., reactance to phase sequence φ*A* leads φ*B* leads φ*C* leads φ*D* …) decreases with increasing phase order.
- The security limited power capacity of the circuit increases with increasing phase order.
- Phase-phase voltage decreases with increasing phase order
- The 'sequence impedances' can be deduced with an analogy to symmetrical components (e.g., the terminology of the six phase sequence names, *ns*, *pt*, ..., was proposed in reference [17]) and these impedances are completely calculable from (4).

Note that λ_m is the discrete Fourier transform of the sequence $\{X_{1,1}, X_{1,2}, \ldots, X_{1,n}\}$ which is the top row of the $X_{n\varphi}$ matrix. In the foregoing, the X matrix is assumed to be completely reactive, but accommodation of resistance and capacitance is readily included. Testing using the X matrix in small simulated implementations of general n-phase systems reveal that:

- There are a large number of transposition sections needed to fully transpose n-phase circuits, namely $(n-1)!/2$ for a circularly configured line. In this context, the term 'fully transposed' means that all the off diagonal terms in X are equal.
- For most cases of practical interest (i.e., practical loading levels), even partially transposed or untransposed circuits do not introduce high levels of unbalance in voltage. The concept of voltage unbalance is generally only defined for the three phase case, but if a generalized n-phase voltage unbalance factor is defines as the negative sequence voltage $|V^-|$ divided by the positive sequence voltage $|V^+|$, then low levels of unbalance factor are observed. Note that the positive and negative sequences are generalized from three-phase technology: for example, positive sequence refers to the phase sequence {phase 1} leads {phase 2} leads {…} leads {phase n} and the negative sequence refers to {phase n} leads {phase n-1} leads {…} leads {phase 1}.
- For high phase order, the loss of a phase (e.g., single pole switching of a faulted phase) results in loss of transmitted power by a factor of $(n_\varphi - 1)/n_\varphi$. This has implications of improved reliability.
- Phase to phase faults in higher phase order systems result in nearly 100% reactive fault currents which are approximately 180° out of phase with the phase voltage. This may make fault detection easier.
- Conversion of existing overhead construction from multiple circuit three-phase to high phase order is generally possible with minimal or no specially constructed equipment. For example, the conversion of a double circuit three-phase line to six-phase is straightforward. As a further example, Fig. 4 shows a comparison of quadruple three-phase circuits converted to one compact 12-phase line (the positive sequence reactance of the compared circuits for the given Drake conductor indicates about a reduction of X^+ by about 14% at 20 foot spacing, and a concomitant increase of the security rating by about 16%).

B. Potential Applications in Overhead Circuits

The most attractive of the polyphase circuits may be the six-phase case. This is because no additional product development needs to be developed to convert two three-phase circuits to six-phase. The most common implementation is the use of a wye connected transformer and an inverted wye connection to obtain the 60^o phase difference needed for six-phase designs. Also, in many existing circuits, no changes in transposition are needed. However, to obtain the full benefits of six-phase circuits, new circuits having reduced right of way and reduced phase spacing are needed.

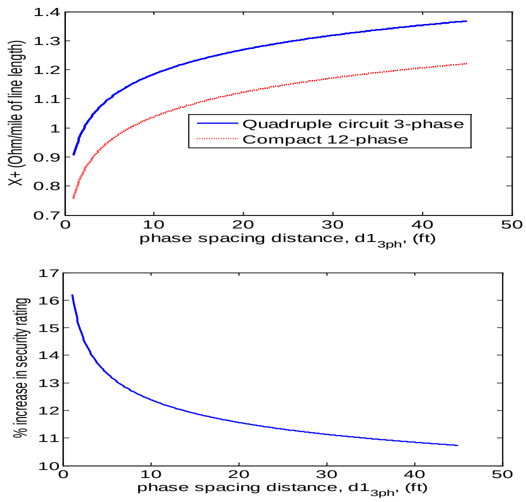


Fig. 4. Comparison of X^+ (upper graph) and increase in security rating (lower graph) for quadruple circuit 3φ upgraded to a compact 12φ design (for GMR of 0.0375 ft. Drake conductor, circularly configured).

For $n_\varphi > 6$, additional benefits are attainable but protective relaying may be more complex, and in order to implement single pole switching, relay logic would need to be developed. This has been reported in part in the literature [18].

The combination of high phase order and phase compaction should be explored as a combined technology. As an example, Fig. 5 shows the decrease in positive sequence reactance of a double circuit three-phase line versus a compact spaced six phase line. Fig. 6 shows the concomitant increase in security rating for a representative conversion of a double circuit three phase line to six-phase.

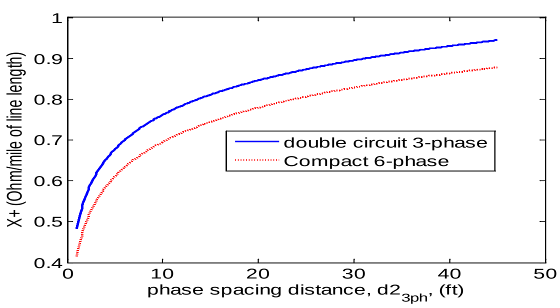


Fig. 5. Comparison of X^+ for double circuit 3φ, and compact 6φ vs. phase spacing of the original double circuit 3φ (for GMR of 0.0375 ft. Drake conductor).

C. Potential Application in Underground Cables

High phase order offers the potential of spatially efficient transmission of power in underground cables due mainly to the reduced phase-phase voltage. Conductors in the cable might be arranged circularly as shown in Fig. 7(b). It is possible to exploit the lower phase-phase voltage as in Fig. 7(a) by using several layers of conductors (note that the voltage from one phase to the next-to-next phase, e.g., phase A to C, is

$$|V''| = |V_{ln}| \sqrt{2\left(1 - \cos\left(\frac{720}{n_\varphi}\right)\right)}$$

which is about 68% of the phase-neutral voltage for 18 phase, 35% of the phase-neutral voltage for 36 phase, and 17% of the phase-neutral voltage for 72 phase). In Fig. 7, a concentric neutral may be used, or (not shown) a sheath neutral might be used.

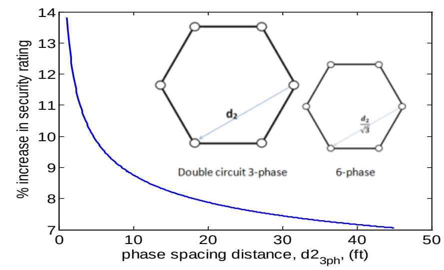
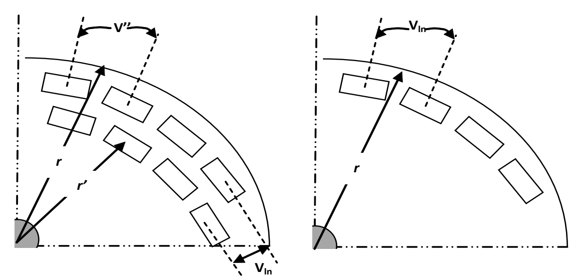


Fig. 6. The percent increase in security rating for comapct 6φ over double circuit 3φ is plotted versus phase spacing (distance d_2) of the original double circuit 3φ.

At very high phase orders, note that the phase-phase voltage is about 90^o out of phase with the phase to neutral voltage and detection of fault currents might be facilitated by detection of the relative phase of the phase current. In a configuration such as that shown in Fig. 7(a), it is possible to 'stagger' phases. Illustrated for a 12 phase application, phases A, B, D, E, G, H, J, K may be in the outer circle of conductors and phases C, G, I and L in the inner circle to balance dielectric stress. The result is a maximal use of the dielectric investment as well as low loss. The potential applications of high phase order cables include high capacity distribution circuits and underground transmission.



(a) Two layer (b) One layer

Fig. 7. (a) orientation of phase conductors in an underground cable arranged concentrically in two layers and (b) arranged in one layer. A quarter round is depicted. The notation V'' refers to the voltage magnitude from phase to next-to-next phase. The conductors (white rectangles) are arranged in a circle.

V. Conclusions

The main conclusions of this report are that there are several innovative transmission concepts that are useful for bulk power transfer. High voltage DC offers compacted right of way, high speed control of power flow, and asynchronous connection. Meshed and multiterminal HVDC technology has matured to the point that these technologies are practical. Relating to AC technologies, six phase (and higher phase order) offers real potential in power transfer enhancement. Phase compaction offers the potential for narrower right of way and higher security rating of comparable conventional designs. Several of these technologies result in right of way utilization in the general range of 10 – 20% greater than conventional designs, but high phase order has the potential of much higher transmission capacity for a given application. For thermally limited circuits, upgrade to HTLS may offer an attractive alternative to alleviate bottlenecks.

VI. Future work

Recommended future work resulting from this effort is focused on four main transmission technologies:

High voltage DC multiterminal and networked systems should be investigated to take advantage of the latest technologies in direct computer control and HVDC circuit breakers. The advantages are asynchronous ties, controllable flows, and more efficient transfer of high levels of power.

Six phase overhead transmission allows the more efficient use of rights of way, potential improvement in reliability, and attainment of these features without the development of new transmission technologies. Although protection of these circuits has been identified as a potential disadvantage, extensive studies indicate that computer relaying overcomes these difficulties.

High phase order overhead and underground transmission has the potential of more efficient use of spatial assets, increased reliability, and higher power transmission for a given investment. The development of single pole switching is likely to enhance reliability since single phase out-of-service has low impact at high phase order.

Phase compaction for overhead transmission engineering offers significant savings in right of way width. The reduction of phase spacing versus management of basic impulse level is recommended for future research. Phase compaction in combination with six (and higher) phase order is recommended.

In addition to the foregoing, it is recommended that innovative transmission technologies that go beyond present mainstream efforts be pursued. Examples of such innovation include the following:

Non-sinusoidal transmission voltages may allow some advantages of both AC and DC. An example is a modified square wave (e.g., a square wave with high frequency components removed): this type of waveform makes better use of the voltage-time continuum (i.e., the integral of $v(t)$ with respect to t) but does not have objectionable high frequency spectral components. This type of waveform may be generated electronically, and there is some advantageous control potential. Specially designed transformers may allow raising / lowering voltage in a simple, low loss way.

Identification of triple point transmission areas for transmission interconnection and power marketing may offer unique economic benefits. This concept is illustrated by the Tres Amigas project [19] in New Mexico in which the eastern interconnection, the Western Electricity Coordinating Council area, and the Texas interconnection (ERCOT, the Electric Reliability Council of Texas) come to a single point. HVDC interconnection of the three areas allows merchant power marketing between the three areas. Another similar location is located at extreme western Texas, southeast New Mexico, and the adjacent Mexican state of Tamaulipas where WECC, ERCOT, and the Comisión Federal de Electricidad (CFE) come together in a single point.

VII. Acknowledgments

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IX. Biographies

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Hierarchical Probabilistic Coordination and Optimization of DERs and Smart Appliances (5.3)

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***Abstract*--Massive deployment of Distributed Energy Resources (DERs) (wind, solar, PHEVs, smart appliances, storage, etc.) with power electronic interfaces will change the characteristics of the distribution system: (a) Bidirectional flow of power with ancillary services, (b) Presence of non-dispatchable and variable generation, and (c) Non-conventional dynamics → inertial-less characteristics of inverters. To manage this system and harness its potential two major approaches have emerged: (1) Market Approach through incentive/price markets and local controls, and (2) (our approach) coordinated approach by the creation of an active distribution system supervised with a distributed optimization tool. This paper describes an infrastructure for monitoring and control supervised by a hierarchical stochastic optimization tool that enables: (a) maximization of value of renewables, (b) improved economics by load levelization (peak load reduction) and loss minimization, (c) improved environmental impact by maximizing use of clean energy sources, and (d) improved operational reliability by distributed ancillary services and controls.**

I. Introduction

Renewables and other distributed resources including storage, smart appliances, PHEVs with vehicle to grid capability, micro-grids, etc. offer a unique opportunity to transform the distribution system into an active and controllable resource with dramatic impact on (a) system economics, (b) primary energy source utilization (including shifts in fuel usage from petroleum to nuclear, natural gas, etc.) and associated shifts in greenhouse gas production, (c) ancillary services and improvements of system stability and security. The characteristics of the distribution system of the future will be: (a) possible bidirectional flow of power as opposed to the present system that is radial with power flow always from the substation to the loads, (b) presence of non-dispatchable generation, (c) non-conventional dynamics of the system due to fast response and inertial-less characteristics of the inverter interface. These new characteristics offer the possibility of active control for the benefit of the entire system.

Control strategies can be divided into two categories (a) incentive/price based market approaches to enable desirable demand response, and (b) coordinated control. Previous research has produced the following conclusions: (a) incentive/price based approaches may result in unwanted behavior, such as shifting and increasing peaks, cycling of thermal units and unpredictability of demand response in cases of need, etc., and (b) centrally coordinated and optimized controls can maximize the benefits from these resources. On the other hand a centrally coordinated and optimization procedure is in general more complex and requires an infrastructure of metering, communications, analytics and controls as well as participation (consent) of customers.

The objective of this research is to develop an hierarchical stochastic optimization method and a supporting infrastructure that coordinates the operation of non-dispatchable resources and other resources including storage, smart appliances, and PHEVs with the ultimate goal being: a) improved system operation and economics, b) improved environmental impact, c) improved operational security, and d) maximize the value of renewables.

The research work focused in defining the requirements of an infrastructure that enables the optimal utilization of the distributed resources (utility and customer owned) and has the additional advantage of providing in real time the available demand response capacity. The infrastructure provides the real time model of the integrated system (utility and customers) via distributed state estimation. The optimization procedure uses the real time model and computes the controls for the overall optimization of the system. While the approach controls the customer owned resources of those customers that participate in the process, a basic constraint of "no inconvenience to the customer" is imposed. The benefits to the utility are substantial and we envision that incentives will be provided to customers with resources (smart loads, renewables, etc.) to participate in the program. In return, this capability will allow utilities to plan their operations more economically and dramatically improve the reliability of the system.

II. Approach/Methods

A. General Description

In order to develop a practical approach to achieve the above goals, a three-level hierarchical stochastic optimization methodology (implemented in real time) as shown in the

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Figure 1 is proposed. The hierarchical method has three levels: (a) distribution feeder optimization, (b) substation level optimization, and (c) system optimization. The three optimization levels are interconnected. In particular, the interface variables (directives) are imposed from a higher optimization level to the lowest level in order to achieve the coordination. The lower level optimization returns a model of the interface variables, present value and limits (aggregate model). The higher level optimization uses the aggregate model of all lower level optimization problems to perform the optimization. For the feeder optimization problem, the above mentioned interface variables (directives) are defined to be a) total stored energy in all feeder resources during the planning period b) minimum reserve and spinning reserve margin in all feeder resources within the planning period and c) VAR resources. A similar set of directives exist between the system and substation optimization problems. The overall approach is illustrated in Figure 1 which shows pictorially the interfaces between the three levels of the hierarchical optimization method.

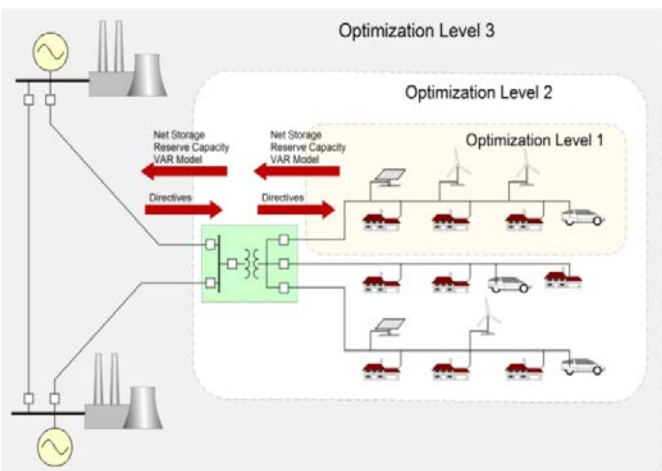

Fig. 1. Overall Approach of the Hierarchical Optimization.

Feeder Optimization: The lower level is referred to as feeder optimization. Feeder optimization covers all the circuits, resources, customers of one feeder of a substation. For this level a real time model of the feeder is used, which is obtained via state estimation as described in the reference [1]. Moreover input data from a short term forecasting procedure are used in order to provide probabilistic models of the feeder loads and the availability of resources like solar panels, wind etc.

Substation Optimization: Typical substations have 2-12 feeders. The operation of these feeders has to be coordinated in order to achieve optimal substation level operation. At the substation level, the aggregate model of each feeder of the substation is used, along with target values from the upper (system) level, in order to generate the targets that have to be achieved for each separate feeder. A stochastic dynamic programming approach is proposed that will determine the optimal directives for the feeder optimization and will ensure optimal operating conditions of the substation over the planning period. Short term forecasting input data are also needed in this level.

System Optimization: The system level optimization is used in order to coordinate the operation of the substations and generate the target values that each substation has to achieve for a system level optimal operation. The aggregate models of the substations are used as input, along with short term forecasted data. A dynamic programming approach is also suggested for this level.

B. Feeder Optimization Formulation and Solution Method

Feeder optimization problem is defined as the optimal scheduling of storage devices, DERs and other resources in a feeder over a specified time period (e.g. one day). For the formulation of this problem it is assumed that the following are given:

1. a feeder with a number of resources and given topology.
2. directives (targets) from the higher optimization level.

The directives, which are defined from the higher optimization level, can be:

- the total stored energy in all feeder resources at the start, the end and specific times of the planning period,
- minimum reserve and spinning reserve margin in all feeder resources within the planning period.
- production cost per unit energy over the planning period.

Given this information, the optimization problem determines the optimal operating conditions for the resources (minimum total operating cost over the planning period) subject to meeting the directives from the higher optimization level. Optimal operating conditions include the best charging and discharging time for the energy storage devices, optimal real and reactive power injection/absorption of the inverter-interfaced DERs, etc.

The mathematical formulation of the feeder optimization problem follows:

$$\min = f\left(\mathbf{x},\mathbf{u}\right)$$

Subject to:

$$E(t_h) = \sum_{si} E_{si}(t_h) \qquad h = 0,\dots,n \qquad (1)$$

$$SR(t_h) \geq \sum_{\substack{si \\ P_{si}(t_h)\neq 0}} (S_{si,N} - P_{si}(t_h)) + \sum_{\substack{gi \\ P_{gi}(t_h)\neq 0}} (S_{gi,N} - P_{gi}(t_h)) \quad h = 0,\dots,n \quad (2)$$

$$R(t_h) \geq \sum_{\substack{si \\ P_{si}(t_h)=0}} (S_{si,N} - P_{si}(t_h)) + \sum_{\substack{gi \\ P_{gi}(t_h)=0}} (S_{gi,N} - P_{gi}(t_h)) \quad h = 0,\dots,n \quad (3)$$

$$\left.\begin{array}{c} E_{si,0} \leq E_{si}(t_h) = E_{si}(t_{h-1}) - P_{si}(t_h)\cdot\Delta t \leq E_{si,N} \\ 0 \leq \sqrt{P_{si}^2(t_h) + Q_{si}^2(t_h)} \leq S_{si,N} \end{array}\right\} \quad (4) \quad \begin{array}{c} h = 0,\dots,n \\ \textit{for all storage} \\ \textit{devices} \end{array}$$

$$0 \leq \sqrt{P_{gi}^2(t_h) + Q_{gi}^2(t_h)} \leq S_{gi,N} \qquad (5) \qquad \begin{array}{c} h = 0,\dots,n \\ \textit{for all generating units} \end{array}$$

$$0 = g(x,u)\,(6)$$

$$0 \leq h(x,u)\,(7)$$

where:

$f(\mathbf{x},\mathbf{u})$: total operating cost of the feeder over (t_0 : t_n).

$E(t_h)$: Total energy stored at all storage devices at instant t_h.

$E_{si}(t_h)$: Energy stored at storage devices at instant t_h.

$P_{si}(t_h)$: Generated power of storage devices at instant t_h.

$P_{gi}(t_h)$: Generated power of generating unit i at instant t_h.

$SR(t_h)$: Spinning Reserve Capacity at time instant t_h

$R(t_h)$: Reserve Capacity at instant t_h

$S_{si,N}$: Nominal capacity of a storage unit i

$S_{gi,N}$: Nominal capacity of a generating unit i

$E_{si,N}$: Nominal energy of a storage device.

Δt : time step = t_h - t_{h-1}

Constraints (1) provide the net stored energy in the feeder from all resources in the feeder. These variables represent directives from the higher level optimization problem. Inequalities (2) and (3) represent the spinning reserve and net reserve capacity of the feeder at each time of the planning period. The variables $SR(t_h)$ and $R(t_h)$ $h = 0,...,n$ also represent directives from the higher level optimization problem. Equations (4) and (5) represent operational constraints of the storage devises and the DERs respectively. Equations (6) represent the power flow equations of the feeder. Inequalities (7) represent operational constraints of the feeder such as bus voltage magnitude constraints and capacity constraints for distribution lines and transformers. Note that directives from the higher level optimization problem are values to specific variables, for example $E(t_0)$, and they are imposed as constraints. The objective function for this optimization problem is the minimization of the total operating cost of the feeder over the planning period. Since peak load production cost is higher than at lower levels, the optimization algorithm favors operating conditions that levelize the load and decrease losses.

At this point, it is emphasized that a quadratic power system component modeling methodology is utilized, i.e. the model of each device is described by the State and Control Algebraic Quadratic Companion Form (SCAQCF). The procedure for the automatic computation of the integrated SCAQCF model of a device can be found in [4], which has the following generic form:

$$I(\mathbf{x},\mathbf{u}) = Y_{eqx}\cdot\mathbf{x} + \left\{\mathbf{x}^T\cdot F_{eqx,i}\cdot\mathbf{x}\right\} + Y_{equ}\cdot\mathbf{u} + \left\{\mathbf{u}^T\cdot F_{equ,i}\cdot\mathbf{u}\right\} + \left\{\mathbf{x}^T\cdot F_{eqxu,i}\cdot\mathbf{u}\right\} - B_{eq} \quad (8)$$

where:

$I(\mathbf{x},\mathbf{u})$: the through variables of the device model.

$\mathbf{x}$: external and internal state variables of the device model,

$\mathbf{u}$: the control variables of the device model.

Y_{eqx} : matrix defining the linear part for state variables.

F_{eqx} : matrices defining the quadratic part for state variables.

Y_{equ} : matrix defining the linear part for control variables.

F_{equ} : matrices defining the quadratic part for control variables.

B_{eq} : constant vector of the device model.

The main advantage of the SCAQCF model is that it enables the automatic synthesis of the feeder optimization problem as well as its solution. Any new resource of component added to the system will be automatically accounted in the optimization as long as its model is presented in the SCAQCF syntax. Also note that by virtue of the quadratic structure of the SCAQCF model, all the analytics of the optimization problem are in terms of quadratic equations. The optimization problem is solved with a barrier method that performs extremely well for this problem.

C. *Substation Optimization Formulation and Solution Method*

The substation level optimization problem is a multistage decision process that defines the optimal directives that have to be satisfied by each feeder over the planning period for the feeder coordination to be achieved. For the formulation of this problem the following information is assumed to be known:

1. a substation with several distribution feeders,
2. the model of the directive variables (present value and limits) for each feeder at each stage k (this model is provided by the feeder optimization problem),
3. performance criteria (e.g., operation cost of the substation), and
4. a planning horizon (e.g., day/week/month/year).

A dynamic programming methodology is applied for the solution of the problem with objective minimal operation cost from the initial stage to the final stage in the planning horizon. Part of the solution output is the optimal values of the directive variables for each feeder at each stage k. The dynamic programming approach is illustrated in Figure 2. The horizontal axis indicates time (stages) while the vertical axis indicates the states of the system at the same stage. A system state i, at stage k is denoted with $X_{i,k}$ and it is defined in terms of the directives for all feeders.

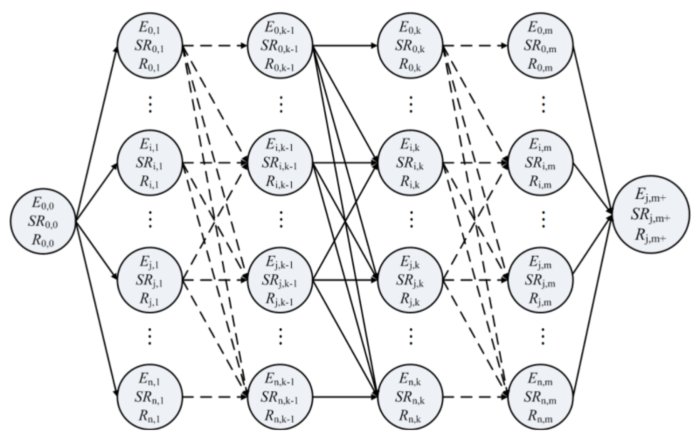

Fig. 2. Dynamic Programming Formulation

The optimal operational cost of state $X_{i,k}$ is calculated by the feeder level optimization problem given the specific directive values of this state.

$$C^*(E_{j,k-1}, R_{j,k-1}, SR_{j,k-1}, E_{i,k}, R_{i,k}, SR_{i,k}, G_A, L)] \quad (9)$$

where:

G_A : the set of available storage and DER units

L : the forecasted load curve of the day k.

The substation level optimization problem is defined as:

$$Min \quad R = E[\sum_k C^*(E_k, R_k, SR_k, G_A, L)] \tag{10}$$

Subject to

$$\begin{aligned} &E_{\min} \le E_k \le E_{\max} \quad k = 0,1,\cdots \\ &R_{\min} \le R_k \le R_{\max} \quad k = 0,1,\cdots \\ &SR_{\min} \le SR_k \le SR_{\max} \quad k = 0,1,\cdots \end{aligned} \tag{11}$$

where:

$$C^*(E_k, R_k, SR_k, G_A, L) \tag{12}$$

represents the optimal cost of the feeder level optimization problem defined in the previous section for the day k for a specific feeder. The dynamic programming formulation is solved by the following forward recurrence formula:

$$\begin{aligned} R^*_{k+1}(E_{k+1}, R_{k+1}, SR_{k+1}) = \min_{E_k, R_k, SR_k} [R^*_k(E_k, R_k, SR_k) \\ + C^*(E_{k+1}, R_{k+1}, SR_{k+1}, G_A, L)] \end{aligned} \tag{13}$$

Subject to:

$$\begin{aligned} &E_{\min} \le E_k \le E_{\max} \quad k = 0,1,\cdots \\ &R_{\min} \le R_k \le R_{\max} \quad k = 0,1,\cdots \\ &SR_{\min} \le SR_k \le SR_{\max} \quad k = 0,1,\cdots \end{aligned} \tag{14}$$

where R^*_k is the optimal cost of operation up to day k.

The above recurrence formula can be easily solved by utilizing the feeder level optimization problem formulation which provides an efficient procedure for the computation of the quantity $E[C^*(E_{k+1}, y_{k+1}, G_A, L)]$.

D. System Optimization Formulation and Solution Method

The system level optimization problem utilizes the aggregate mathematical model of the substation level optimization problem in order to coordinate the operation of all substations. A stochastic dynamic programming methodology is also utilized for this level. The formulation of the problem is similar to the formulation of the substation optimization problem given in section III.C.

III. Results

A. Test Case for the Hierarchical Optimization Approach

In this section we present an example test system to demonstrate the proposed hierarchical optimization and coordination scheme. The real time control of storing device charging time and utilization of distributed energy resources (DERs) is demonstrated. Comparative results for the same example test system, without or with the proposed control scheme, are also provided.

Figure 3 illustrates the single line diagram of the example test system. A substation with 3 distribution feeders is shown. Each feeder supplies residential and industrial loads. Each feeder is a 400 Ampere, 12.47 kV feeder; nominal load is 8.6 MVA. The peak load of the feeder is 4.5 MVA or about 50% of its capacity. We assume a 3.5% penetration of DERs (total of 300kW). In addition there are distributed storage devices of total 300 kW capacity (3.5%) with 600 kWhr storage capacity.

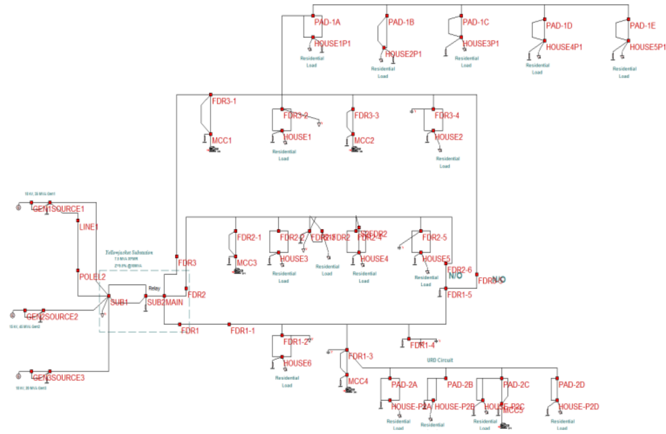

Fig. 3. Example Test System

We simulated the distribution system without and with the hierarchical optimization algorithm (in this case a two level problem). The optimal control for charge/discharge storage devices and usage of DERs is computed for a 24 hour horizon. Figure 4 shows the load curves for the three feeders respectively and Figure 5 shows the substation load curve (aggregate of all feeders). The red curve is the optimized load curve while the blue one is the non-optimized load curve.

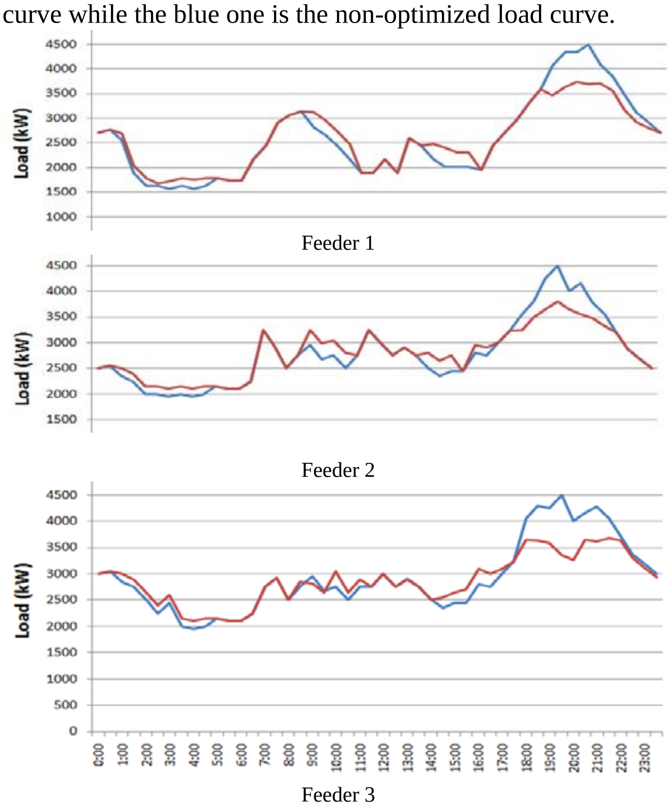

Fig. 4. Non Optimized and Optimized Load Curve of Feeders 1, 2 and 3

The results indicate that with the proposed optimized charge/discharge schedule and utilization of the DERs, we managed to flatten the peak load by approximately 19%, without shifting the peak and without affecting the end customer (total energy is the same for all cases). Note that a 3.5% penetration of these resources enables a 19% peak load reduction.

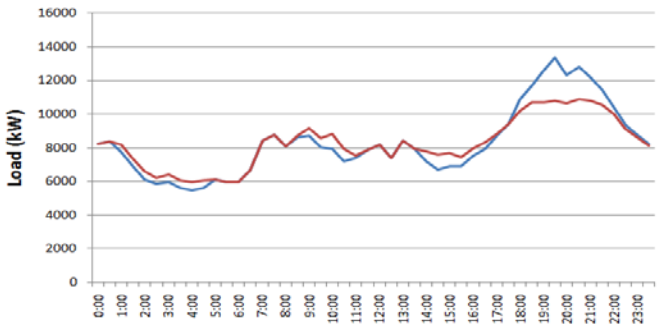

Fig. 5. Non Optimized and Optimized Load Curve of the Substation

B. Business Analysis for the Proposed Approach

The proposed method requires hardware (metering and communications) as well as the hierarchical optimization software. A business case analysis has been performed to determine the economic benefits of the approach. The probabilistic production cost (PPC) analysis tool (similar to PROMOD) has been used for an independent evaluation of the costs, reliability and impact on the environment. Specifically, the following have been computed: expected operating cost of the system, expected pollutants (environmental impact) and expected system reliability (using several metrics, such as LOL probability and expected un-served energy).

The objective of the business case analysis is to compare the operation of the system with and without the proposed method and assess (a) the operating cost, (b) the fuel utilization and (c) the pollutants, given the apparent load of the feeder for both the non-optimized and optimized scenarios. Figure 6 illustrates the procedure for the business case analysis.

A made up utility system has been used as a test bed. It is assumed to have a capacity of 22,280MW and 40 generator units with four types of fuel resources (coal, nuclear, oil and natural gas). Details on the data for the test-bed system are given in [2].

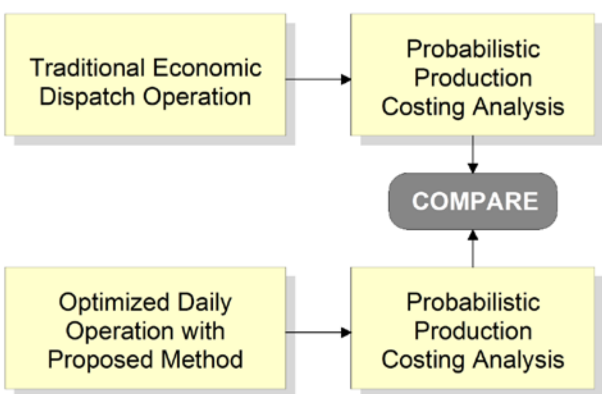

Fig. 6. Business Case Analysis Methodology

A typical summer daily load curve was used and was considered to be the “original” non-optimized load curve for the analysis. The "original" load curve is illustrated in blue in Figure 5. Assuming a 6.6% of penetration of DERs (wind turbine, photovoltaic) and storage devices, an “optimized” load curve of the system is obtained by applying the hierarchical optimization scheme as described in section II. The "optimized" load curve is illustrated in red in Figure 5.

The PPC analysis was performed for the optimized and non-optimized systems. The results of the PPC analysis for the non-optimized and optimized system for a simulation period of 24 hours are summarized in Table 1.

TABLE I
FUEL COST BASED ECONOMIC DISPATCH RESULTS

	Non-Optimized Scenario	Optimized Scenario
Loss of load probability	0.04173	0.00227
Generated energy (MWh)	297,841.70	297,018.59
Un-serviced energy (MWh)	1,103.69	32.89
Total production cost (k$)	8,234.67	7,945.56
Average production cost (cents/KWH)	2.7648	2.6751
Total CO2 emissions (kg)	125,671,208.46	124,906,337.60
Total NOx emissions (kg)	381,722.74	379,289.92

The annual production cost savings are:

$$(8234.674 - 7945.566) \times 365 \times 1000 = \$105,520,000$$

The reliability of the system has improved since the expected loss of load probability is decreased from 0.04173 to 0.00227 and the expected un-serviced energy decreased from 1103.69 MWh to 32.89 MWh. Table 2 illustrates the estimated cost of the proposed infrastructure (assumed price of DER/storage: $1/W, assumed penetration 6.6%). The investment for DERs and storage is estimated to be 1,470 M$. Additional investment for AMIs is expected to be 200 M$, software and computing equipment 5 M$.

TABLE II
INVESTMENT COST

Investment	Cost (Million $)
DERs & Storage	1,470
AMI	200
DMS Software & Hardware	5
Total	1,675

The concept of the annualized equivalent cost (AE) is used to compare the investment to the benefits. Assuming an interest rate of 8% and a 20 year lifetime, zero salvage value, the AE is:

$$1{,}675 = \sum_{n=0}^{19} \frac{AE}{1.08^n} \rightarrow \text{AE=\$157.96 million}$$

The annualized equivalent cost is higher than the annual estimated savings of $105.52 million. However both figures are in the same order of magnitude. It is important to observe that cost of smart grid technologies will decrease as new technologies develop and the demand increases. It is therefore conceivable that in the near future the implementation of smart grid technologies will be economically attractive. It is also pointed out that the savings resulting from generation deferment expenditures have not been included in above evaluation. These savings will further make the smart grid approach more attractive.

The proposed method has two very important side benefits: (a) it alleviates the cycling of thermal units due to the variability of renewable generation, and (b) it increases the capacity credit of variable (renewable) generation. Details are omitted due to space restriction but can be found in [2] and [3].

IV. CONCLUSIONS

This research project provided a smart grid infrastructure composed of software and hardware tools, supervised by a hierarchical optimization algorithm, that enables a practical and efficient utilization of customer and utility owned resources, take advantage of their capabilities and operate and coordinate them in a way that will result in an optimal system operation, without affecting customer convenience and in an economically attractive manner. The paper presented such a system and provided economic justification of the overall approach. The work is summarized as follows.

Accomplishments: Defined the requirements of an infrastructure that enables optimal use of distributed resources (both utility and customer-owned) through real-time, hierarchical monitoring and control. Created a stochastic optimization algorithm that coordinates the operation of non-dispatchable resources (e.g., renewables) and other resources including storage, smart appliances, and PHEVs. This centralized approach relies on a sophisticated infrastructure of metering, communications, analytics and controls as well as on participation (i.e., consent) of customers.

Results: Based on comprehensive studies of application on utility-scale systems, a business case analysis justifies the investment in the proposed optimization scheme. The analysis includes an economic assessment based on anticipated benefits on system operation, economics and reliability versus the anticipated costs. This integrated approach to power system operations maximizes the value of renewable generation technologies.

V. FUTURE WORK

The potential of the propose approach is extremely promising. The approach should be exploited for providing reserve capacity by determining in real time the amount of load that can be released by customers without inconveniencing the customers. Some preliminary work in this area has been performed. The method can be also used to determine how the degree by which the variability of renewables can be mitigated without the necessity for large storage plants. Finally, the approach should be demonstrated in an actual distribution system.

VI. ACCESS TO PRODUCTS

The object oriented hierarchical optimization tool is a research grade program. It is available by contacting one of the authors.

VII. ACKNOWLEDGMENT

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IX. BIOGRAPHIES

A. P. Sakis Meliopoulos (M ’76, SM ’83, F ’93) Georgia Power Distinguished Professor. He is active in teaching and research in the general areas of modeling, analysis, and control of power systems. He holds three patents and he has published over 220 technical papers. In 2005 he received the IEEE Richard Kaufman Award and in 2010 he received the George Montefiore award. Dr. Meliopoulos is the Chairman of the Georgia Tech Protective Relaying Conference, a Fellow of the IEEE and a member of Sigma Xi.

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Decision-Making Framework for the Future Grid (5.1)

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Georgia Institute of Technology

***Abstract*—This paper presents a decision-making framework that encompasses all the emerging decision makers across the electricity grid, and two specific decision-making mechanisms. The conceptual framework developed links the various decision making agents to their individual goals, to the various decision points, and to the objectives of the grid at the various spatial and temporal scales. The first mechanism consists of a scheduling algorithm based on mixed-integer linear programming allowing residential users to optimally schedule their energy use in a dynamic pricing environment. Benefits include economic gains for electricity users and performance gains for electricity providers. The second mechanism consists of a method to optimally design electricity price signals so that, when users maximize their individual benefit, they adopt an energy schedule that maximizes at the same time the provider's benefit. Potential benefits include enhancing the economic dispatch, bridging the gap between individual and system objectives, and supporting new business models for electricity providers.**

I. Introduction

Decision-making – either automated or through humans – is at the core of the success of any enterprise or industry. Because the future electricity grid has new goals, more stringent requirements, and increased uncertainty and complexity, a significant portion of the existing decision-making processes in the industry are already or will soon become obsolete. Contrary to the traditional grid components, all the smart devices, engineering subsystems, and economic agents present in emerging grids will make decisions in order to achieve their individual objectives and the overall goals of the grid. Thus, the secure evolution of the grid and its ability to realize its objectives depend on the decision-making capabilities embedded within the grid's control and management.

Among the challenges that have been identified in decision-making are: the lack of a "common semantic model" [4] to represent the various decision-making entities involved; the emergence of new temporal and spatial scales; the difficulty to process massive amounts of data in a centralized fashion; the shift from instantaneous optimization (e.g. SCOPF) to complex scheduling due to demand shift, PHEV, and utility-scale storage; the need of novel schemes that enable sustainability objectives through demand mechanisms; and considerations of consumer behavior in energy utilization and energy efficiency investment.

Under this project, our objectives were twofold. First, to develop a decision-making framework for the future electricity grid that encompasses both current and future decision making entities, covers multiple decision scales (including spatial and temporal scales), addresses decision complexity through layered abstractions, and uncovers gaps and technological needs as the industry evolves into the future grid. We report on the work completed under this first objective in section II.

Second, to develop and demonstrate specific decision-making mechanisms ensuring that the goals of the future grid can be met at both the local and the system levels. This second aspect of our work particularly focused on residential energy users and their interactions with electricity providers. This is consistent with several comments expressed during the Future Grid Initiative Workshop held in December 2011 regarding (1) the need to clarify the role residential consumers will play in the future grid, (2) the need to understand how residential consumers will respond to incentives, (3) the need to understand the value of the new capabilities being developed at the residential level, including generation and storage, and (4) the need for grid operators to accurately and dynamically model the future behavior of residential actors.

Under this second objective we developed two specific decision-making mechanisms. In section III, we present a scheduling algorithm based on mixed-integer linear programming (MILP) that allows residential users to optimally schedule their energy use in a dynamic pricing environment, for a given time horizon. In section IV, we report on a method to optimally design the electricity price signals sent to residential users. A price signal is "optimal" when it induces residential users to adopt an energy schedule that maximizes the electricity provider's benefit –or alternatively the social benefit– when they maximize their own individual benefit.

Section V presents the conclusions resulting from the work completed under this project, and section VI discusses future work that will build on these conclusions.

II. Decision-Making Framework

A. Approach

1) Towards a New Representation of the Grid

In decision-making, the concept of *bounded rationality* is the idea that rationality of individuals is limited by the information they have, the cognitive limitations of their minds,

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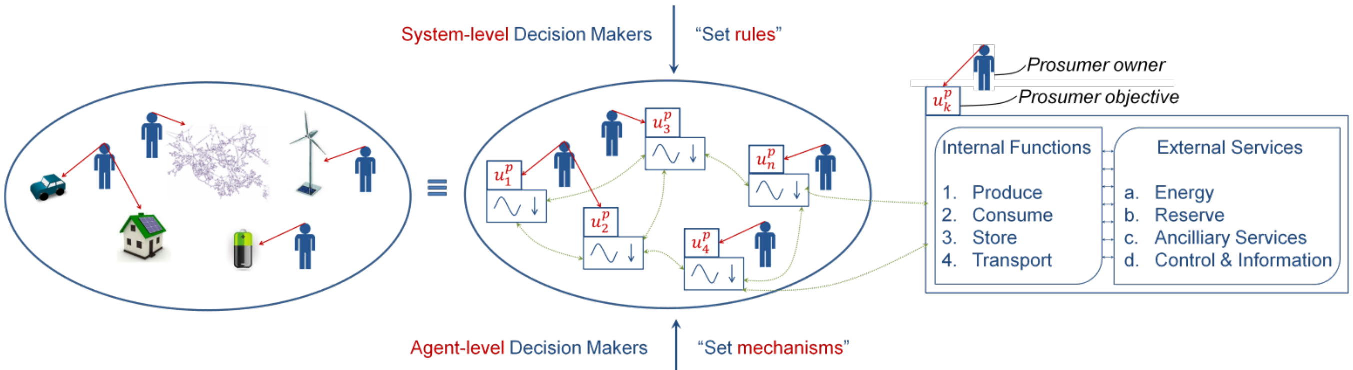

Fig. 1. Prosumer-based representation of the electricity grid.

and the finite amount of time they have to make a decision [5]. Because decision-makers lack the ability and resources to arrive at the optimal solution, they instead apply their rationality only after having constructed simplified models of real-life situations [6].

In the electricity industry, the simplified model that has traditionally been in use to describe the grid divides the electrical system into four main categories: generation, transmission, distribution, and energy utilization. This classification dates back from the Westinghouse concept of a universal supply system displayed at the Chicago exposition of 1893, and first implemented at the Niagara Falls [7]. The current use of the four-category model goes well beyond the boundaries of engineering disciplines. For instance, the “electricity value chain” in power systems economics is traditionally characterized using the four-category representation, and specific policies and policy institutions have been developed over time for each of the four segments.

It is notable that in all the major planning reports or roadmaps released over the past ten years [8-14], new objectives, new properties, new functionalities for the electricity grid are discussed, but the underlying model on which the stakeholders project their goals and solutions is always –implicitly or explicitly– the four-category model.

However, this traditional representation is becoming less and less accurate to serve as a simplified model for the grid and to guide decision-making because the realities it represents have been changing and evolving over time.

First, a *new* function, the energy storage function, is emerging [15]. This new function does not fit into the traditional representation.

Second, there has been a trend over the past decade to move from four differentiated categories limited to perform *one* function to undifferentiated entities performing *multiple* functions. This is particularly noticeable at the end-user level: while end-users were in the past limited to consume electricity, they can now produce (e.g., solar panels), store (e.g., stand-alone storage system, EV battery), and even inject electricity back into the grid [1-3]. They can also reduce demand, acting as a virtual source. The traditional classification model does not accommodate for these developments.

Third, the electrical grid has evolved from a vertically-integrated physical system –limited to carrying electrons from generation units to end-users– to a complex system of systems equipped with new communication [16] and computational capabilities [33]. This move towards distributed cyber-physical systems comes with a significant fragmentation of the decision-making entities concerned with the grid. Until the first deregulations of electric utilities in the 1990s, the decision-making processes related to the planning and operation of the electrical grid were fairly centralized, vertically integrated, and supervised by a limited number of decision-makers. Since then, the number and diversity of decision-makers has continuously been increasing, each pursuing their own individual objectives related to economic optimization, reliability, sustainability or energy security. The traditional model initially describing a purely electric and vertically integrated system does not reflect all these recent developments.

Thus, our first objective under this project consisted of developing a new and more flexible framework that accommodates the energy storage function as well as the emerging entities performing multiple functions while pursuing their individual objectives.

For the purpose of this framework, the concept of *energy prosumer* was developed. Energy prosumers are cyber-physical entities that can consume, produce, store and/or transport electricity. They have their own objectives associated with the control and utilization of electricity. These objectives are aligned with the goals and preferences of the prosumer owners –individuals or organizations. They can also exchange energy services externally with other prosumers.

Any decision-making component in today’s electricity grid can be modeled as a prosumer. A home, a building, a power transformer are each prosumers. A utility grid, a microgrid, and a laptop computer can also be represented as prosumers. The prosumer abstraction is also adapted to the future evolutions of the grid where each component is likely to gain access to additional functions. Therefore, a simplified model based on prosumer interactions is inherently flexible and scalable, and can be proposed to describe the future grid.

2) Prosumer and System Levels

Under the proposed representation, the objective functions set at both the prosumer and system levels as well as the concepts of *rules* and *mechanisms* defined in hierarchy theory [17] can be used to characterize the grid and its constitutive entities from a decision-making standpoint (Fig. 1).

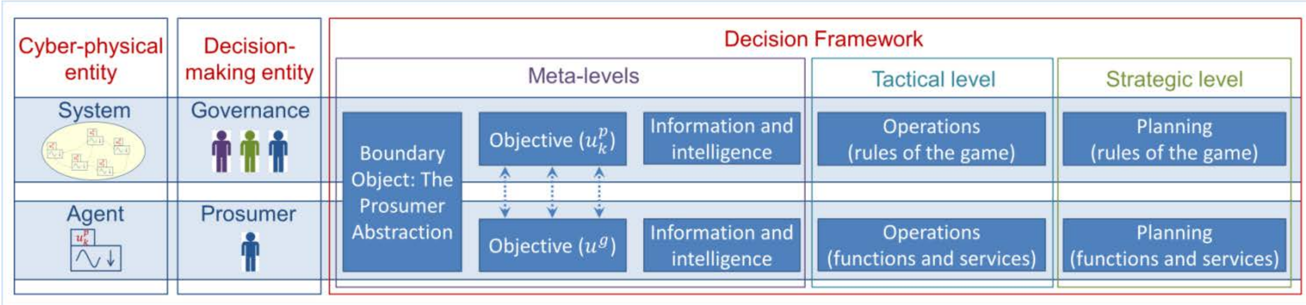

Fig. 2. Mapping of the decision levels to the hierarchical levels

At the system level, a community of decision makers consisting of prosumer owners, experts and elected officials set objectives for the entire grid. These objectives can be expressed using a vector function $\vec{u}^g$ that varies over time as the various actors gain a shared understanding about what the future grid should look like, and how their environment is changing. Decision-makers at the system level also set *rules* that constrain both the way prosumers buy and sell energy services, and the way their internal functions are implemented.

At the prosumer level, prosumer owners have their own goals and preferences associated with the control and utilization of electricity. Their objectives are based on a complex set of values (including economic, reliability, or sustainability aspects), and their objective functions are also best represented by vectors $\vec{u}_k^p$ laying in multi-dimensional spaces, and varying over time to adapt to a changing environment. Prosumer owners also set *mechanisms* that allow them to pursue their objectives within the rules set at the system level.

An important distinction between the prosumer and system levels lies in the types of values that inspire the formulation of their respective objectives. "Citizen values" play an important role in the way decision makers set their objectives at the system level. In contrast, "consumer values" are likely to be dominant at the prosumer level (e.g., [32]).

3) Decision-Making Framework

Several levels of decision can be identified at both the prosumer-level and the system-level (Fig. 2). First, a set of three meta-levels: (1) agreeing on a representation of the system (a *boundary object*); (2) deciding on an objective function, either $\vec{u}_k^p$ for prosumer *k*, or $\vec{u}^g$ at the grid level; (3) defining which type of information, and which type of intelligence (or computational capabilities) will be needed to pursue this objective function. Second, a tactical (or operational) level, which consists of making the most of the resources currently available. For prosumers, this tactical level consists of making the most out of the functions and services currently available locally. At the electricity grid level, the tactical level consists of making the most out of the current rules –policies and/or regulations– in order to get closer to the objectives set by the community of decision makers. Third, a strategic (or planning) level which consists of deciding which new functions or mechanisms (prosumer perspective), or which new rules (system perspective) will be needed in the future to better adapt to the changing environment and get closer to the objectives pursued.

In addition to the temporal aspects related to the planning and operation of the various energy functions and services (Fig. 2), the prosumer owners are also to decide which level of cooperation they want to pursue. This cooperative dimension ranges from going completely off grid (pure optimization), to pure competitive strategies (Nash equilibrium), to engaging in some form of cooperation with other prosumers.

B. Implications

The new representation proposed based on the prosumer concept can serve as a powerful replacement for the traditional representation of the grid that is too rigid to communicate information about the future electricity grid across multidisciplinary contexts and accommodate for ongoing changes affecting the grid.

The representation developed can also be used –and is actively used within the Advanced Computational Electricity Systems Laboratory at Georgia Tech– to foster collaborative research on the future grid, support innovation coming from multidisciplinary collaborations, and help create shared understanding among the various decision makers. The authors are preparing a policy paper elaborating on this topic.

Finally, the conceptual framework developed –and consistent with the prosumer-based representation of the grid– links the various decision-making agents to their individual goals, to the various decision points, and to the objectives of the grid at the various spatial and temporal scales, covering both tactical and strategic aspects.

III. Scheduling Algorithm for Residential Prosumers

In this section, we discuss the first of two specific decision-making mechanisms that we developed and demonstrated as part of this project.

A. Approach

Major forces are creating a new paradigm on residential electricity markets. New *technologies* are being deployed including advanced meters, controllable appliances, distributed generation, energy storage systems (PHEV batteries, stand-alone storage systems), and communications capabilities. New *legislations* are being proposed to allow electricity consumers –and any third parties they designate– to access their electricity usage and pricing information [18, 19]. Finally, new dynamic *pricing policies* are likely to be implemented at the retail level over the next years [20-23].

These multiple developments will contribute to enabling increased customer participation, one of the major objectives of the future grid [24]. Demand response actions in particular, could represent up to 45% of the expected smart grid benefits in the U.S. over the next decade [25].

However, some of these changes have already caused backlash from customers, forcing for instance some energy providers to offer smart meter opt-out programs [26]. Stakeholders' concerns include higher electricity bills [27], cyber-security, and privacy issues [28-30]. With new technologies deployed and new pricing policies implemented, the number of options offered to residential customers in terms of choices increases drastically. This also increases the number of decision parameters and makes home energy management too complex for the common user to solve manually. Additionally, while customers value usage or pricing information, they also want to be hands-off: the per capita time spent consuming information in the U.S. has risen nearly 60 percent from 1980 levels [32]. Increased complexity and information saturation eventually result in highly suboptimal energy utilization with customers not scheduling demand optimally, possibly leading to electricity bills higher than before under a dynamic pricing environment.

Additional concerns from electricity providers and policy makers include the depth of impact that generalized dynamic pricing policies could have on consumption levels, the actual consumer's ability to respond to price signals, and the practical implementation of these pricing policies. To address these concerns, advanced modeling of residential electricity consumers in dynamic pricing environment is required.

The first decision-making mechanism that we developed as part of this project consists of a scheduling algorithm based on mixed-integer linear programming (MILP) that allows residential prosumers to optimally schedule their energy use in a dynamic pricing environment, for a given time horizon.

The optimization model integrates distributed generation capabilities, storage capabilities, controllable and non-controllable appliances, as well as thermodynamic modeling. Among the controllable appliances, both interruptible (e.g., HVAC systems) and non-interruptible appliances (e.g., washing machine) are considered. Uncertainty is handled through a robust optimization approach which minimizes the impact of stochastic inputs on the objective function while preserving acceptable running times.

The optimization constraints considered can be organized into four categories. Physical constraints, including the maximum charging and discharging rates of the storage system, the thermal capacity of the HVAC system, the continuity of the room temperature function, and the circuit limit at the point of common coupling (PCC) with the distribution network. Modeling constraints, including the number of times each appliance is to be scheduled, and the fact that a given appliance cannot be scheduled more than once per time interval. Comfort constraints, in terms of room temperature and scheduling preferences. And market constraints, in particular the fact that any price signal always comes with a cap on the maximum electricity amount delivered. This cap reflects the limited capacity of the distribution grid as well as other network contingencies that the provider must account for when formulating an offer.

The possibility to trade electricity with multiple grid providers – or with a single provider offering multiple price signals to differentiate offers based on emission levels – is integrated. A detailed discussion of the problem formulation and optimization can be found in [3].

B. *Results and Implications*

In order to evaluate the performance of the decision-making mechanism developed, a reference case is defined where residential users have limited decision making capabilities to optimize their energy usage. Several simulation scenarios are tested against this reference case, with the technology capabilities being incrementally increased. In addition to the objective function $\mathcal{C}$, the peak-to-average ratio (PAR) is also computed for each scenario considered. Tables I and II present the simulation results.

Simulation results show that the proposed decision-making mechanism always outperforms the reference case of limited decision-making capabilities. In addition to the economical gains observed for the residential users, performance gains are observed for the providers in term of decreased peak-to-average ratio. A more detailed discussion of the computational performance as well as a comparison with perfect forecast scenarios can be found in [3]. The completed work on energy scheduling algorithms supports the need perceived at all levels to clarify the role residential consumers will play in the future grid as decision makers –in particular their capacity to respond to incentives– and the value of the new capabilities being developed at the residential level.

From an industry or policy perspective, the scheduling algorithm developed can be used to simulate and analyze the impact of the various ongoing changes on residential electricity markets–and in particular the use of dynamic pricing as a tool for effective demand side management.

TABLE I
COMPARISON BETWEEN REFERENCE AND PROPOSED METHODS FOR ONE PROVIDER

Technology	Reference case, real-time prices (R-RT case)		Reference case, day-ahead prices (R-DA case)		Proposed algo., robust approach	
	$\mathcal{C}$ ($)	PAR	$\mathcal{C}$ ($)	PAR	$\mathcal{C}$ ($)	PAR
Load scheduling	18.29	4.19	14.86	4.18	13.11	2.07
+ Storage	16.67	3.75	13.61	4.17	10.39	1.18
+ Ability to sell	16.79	3.49	13.28	3.78	10.18	1.00
+ Solar panels	7.38	4.25	6.98	4.69	4.55	1.00
+ Genset	5.02	4.54	6.82	5.18	4.40	1.00

TABLE II
COMPARISON BETWEEN REFERENCE AND PROPOSED METHODS FOR THREE PROVIDERS

Technology	Reference case, real-time prices (R-RT case)		Reference case, day-ahead prices (R-DA case)		Proposed algo., robust approach	
	$\mathcal{C}$ ($)	PAR	$\mathcal{C}$ ($)	PAR	$\mathcal{C}$ ($)	PAR
Load scheduling	14.35	4.18	14.17	4.18	12.78	1.55
+ Storage	13.50	3.49	13.02	4.11	10.26	1.41
+ Ability to sell	13.48	3.49	11.52	3.70	6.23	1.02
+ Solar panels	4.39	4.29	6.43	4.66	0.59	1.01
+ Genset	2.53	5.18	6.22	5.19	0.42	1.01

From a consumer's perspective, this algorithm can be used to implement a home energy controller, automate the response to dynamic price signals, and minimize energy costs. Residential actors must be provided with the appropriate decision tools to allow them to contribute to the objectives of future grid while being hands-off.

In addition to their prescriptive potentials (provide concrete guidance on how decision makers should act), scheduling algorithms therefore have descriptive potentials (illustrate through simulations why decision makers could be better off if new technology or policy are implemented) and normative potentials (demonstrate how decisions should be made so that these changes are effectively realized).

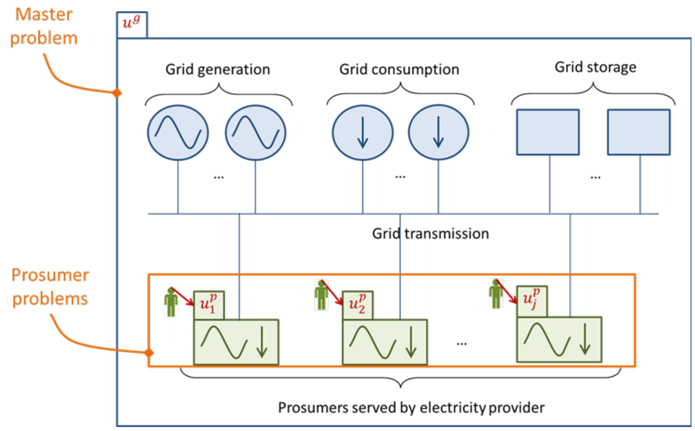

Fig. 3. Modeling concept for optimal pricing design

IV. Optimal Design of Electricity Price Signals

In this section, we discuss the second decision-making mechanism that we developed and demonstrated under this project.

A. Approach

Several factors show that dynamic pricing programs are very likely to expand significantly over the next decade at the retail level, in particular the fact that up to 70% of peak demand reduction could result from dynamic pricing programs [20]. We provide a more detailed discussion on dynamic pricing programs in [2].

The concept we pursued with this second mechanism consists of the optimal design of electricity price signals so that, when residential prosumers maximize their benefit individually (cf. section III), they adopt an energy schedule that maximizes *at the same time* the electricity provider's benefit, or alternatively the social benefit.

The mechanism can be decomposed into two successive steps. The first step consists of an extended economic dispatch which includes both the electric assets controlled by the provider (including generation units and large scale storage systems), and the assets controlled by the residential prosumers (including domestic appliances, EVs and distributed generation and storage). This extended economic dispatch (defined as the "master problem"), is formulated as a linear program. Program variables include the amount of energy consumed by each prosumer, the energy exchanged between the prosumers and the grid, the variables controlling the grid generation, and the control variables for the storage systems. This first step returns an optimal master schedule that specifies how each asset should be scheduled to maximize the provider's benefit (or the social benefit).

The second step consists of determining which price signal should be sent to the residential prosumers to induce them to schedule their assets according to the corresponding desired schedules returned by the master problem. This second step involves the use of a parametric trial-and-error algorithm that was developed to guide the price search. The heuristic used consists of increasing (resp. decreasing) the selling price for a given time period when the prosumer consumption is higher (resp. lower) than desired. A similar heuristic is used to design the buying price when home-to-grid operations are enabled.

B. Results and Implications

A pilot simulation involving 1,000 distinct prosumers was conducted as a proof of concept (Tables III and IV).

TABLE III
RUNNING TIMES (4-CORE MACHINE)

Optimization problem	Running time (s)
Master problem (initial)	20.49
Price generation algorithm (for 1 prosumer)	$\mu = 1.94$ $\sigma = 1.95$
Master problem (final balancing)	<1

TABLE IV
ERRORS (4-CORE MACHINE)

Error monitored (over 24 hours)	Value
Error between desired and obtained *individual* prosumer schedules	$\mu = 11.4\%$ $\sigma = 16.5\%$
Error between desired and obtained *aggregated* prosumer schedules	4.9%

From an industry perspective, the proposed mechanism allows utilities to enhance economic dispatch by influencing the way resources located downstream of the meter are scheduled through the use of price signals and opens a path for new business models as electricity providers transition to the future grid and adapt to its new rules and mechanisms.

The approach taken also presents the advantage of integrating many of the future grid components (consumer participation, distributed generation and storage, dynamic pricing, decision algorithms at the prosumer level, asset optimization, etc.) while preserving the current architecture of the electricity industry. In that sense, it can be seen as a good transition towards a future architecture which will require these new components, but may use them differently.

Finally, the optimal pricing strategies could help bridge the gap between the consumers' individual objectives and the system objectives.

V. Conclusions

The prosumer concept serves as a powerful abstraction to model decision-makers in the future grid. It can also serve as a medium to enable cross-disciplinary understanding and collaboration on future grid research, fostering innovation in the long term.

Sustainability objectives can be directly included in the prosumer objective functions. Both mechanisms developed as part of this project support enhanced modeling of distributed generation and energy storage.

The work part of this project is a) *prescriptive*, providing concrete guidance on how decision makers should act, b) *descriptive*, illustrating through simulations why decision makers could be better off if new technology or policy are implemented, and c) *normative*, demonstrating how decisions should be made so that the objectives of the future grid can be realized.

VI. Future Work

Future work includes a policy paper discussing how the concept of energy prosumer can be used to foster collaborative research on the future grid, support innovation coming from multidisciplinary collaborations, and help create shared understanding among the various decision makers. Future work also includes testing the pricing design mechanism proposed on large-scale cases using a HPC cluster by decomposing the optimization problem into distributed problems coordinated by the master problem (Fig. 4). Potential fairness issues will also be analyzed.

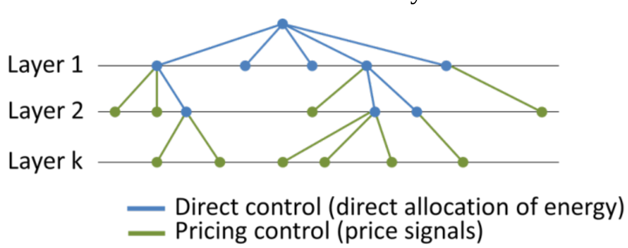

Fig. 4. Layered decomposition fitting utility model

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VIII. Biographies

Tanguy Hubert is a graduate of the École Supérieure d’Électricité (Supélec), Paris, France, and received the M.S. degree in electrical and computer engineering from the Georgia Institute of Technology, Atlanta, in 2010. He is working toward the Ph.D. degree in the School of Electrical and Computer Engineering, Georgia Institute of Technology. He has conducted research for, or supported by, GE Energy Services, the French Department of Energy, and the U.S. Department of Energy, and was the recipient of a Sam Nunn Security Fellowship in 2011-2012. His current research focuses on smart consumer modeling and optimal design of dynamic pricing policies for retail electricity markets. His areas of interest also include energy policy design and implementation, renewable energy integration in developing countries, and energy security.

Santiago Grijalva received the Electrical Engineer degree from EPN-Ecuador in 1994, the M.S. Certificate in Information Systems from ESPE-Ecuador in 1997, and the M.S. and Ph.D. degrees in Electrical Engineering from the University of Illinois at Urbana-Champaign in 1999 and 2002, respectively. He was a post-doctoral fellow in Power and Energy System at the University of Illinois from 2003 to 2004. From 1995 to 1997, he was with CENACE as engineer and manager of EMS Software Department. From 2002 to 2009 he was with PowerWorld Corporation as a senior software architect and consultant. He joined the Georgia Institute of Technology in 2009, where he is an Associate Professor of Electrical and Computer Engineering. His areas of interest are power system computation, informatics and economics, renewable energy integration, and intelligent energy infrastructures.

Robust and Dynamic Reserve Requirements (1.3)

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***Abstract*—Reserve requirements are integral to ensure N-1; however, network congestion threatens reliability by limiting the deliverability of reserves. Uncertainties from load, area interchange, renewable generation, and contingencies make it difficult to predict transfer capabilities and manage congestion. New innovative methods that better manage uncertainties are necessary to ensure system reliability in an economical fashion. This paper summarizes a portfolio of methodologies to determine reserve zones and reserve levels to mitigate congestion in the security-constrained unit commitment (SCUC) problem. Analyses on the IEEE 73-bus and 118-bus test cases show the proposed methods adapt well to changing system operating conditions to achieve reliability at less overall cost.**

I. Introduction

Past research focuses extensively on determining how much reserve is sufficient to re-balance the system following random disturbances. References [5]–[9] acquire reserve to satisfy probabilistic risk thresholds, [10]–[11] minimize a weighted sum of cost and reliability, and [12]–[14] use iterative schemes to determine reserve levels. However, none of these policies guarantee a reliable solution as they do not consider the *locational* aspects of reserves. Acquiring operating (spinning and non-spinning) reserve equal to the largest contingency (generator or transmission) does not guarantee N-1 since congestion can prevent the deliverability of reserve. Reserve zones impose local requirements in order to improve reserve deliverability. However, there may still be intra-zonal congestion and identifying the optimal amount of reserve sharing between zones is not trivial.

Since existing reserve policies used within day-ahead security constrained unit commitment (SCUC) fail to guarantee N-1, operators conduct contingency analysis to determine if any post-contingency congestion inhibits reserve from being delivered. Today, operators must implement *out-of-market corrections (uneconomic adjustments)*, i.e., the operator uses his/her knowledge, or reference material, to obtain an N-1 reliable solution when reserve is not deliverable. For example, when a generator's reserve is not deliverable due to congestion, the operator disqualifies the unit from providing reserves (reserve downflags) and obtains the needed reserves from alternative units. While such procedures can produce N-1 reliable solutions, they are costly since operator discretion and knowledge dictate solution quality. These procedures also bias market solutions, e.g., the locational marginal prices (LMPs).

While reserve zones improve reserve deliverability, there are shortcomings with existing practices: 1) there does not exist a mathematical foundation behind the determination of reserve zones; 2) static reserve requirements generated based on historical information will be less accurate with higher levels of intermittent renewable resources; 3) the cost of out-of-market corrections (uneconomic adjustments) will increase since static reserve requirements are unable to appropriately account for dynamic operating conditions.

This research develops robust and dynamic reserve polices for day-ahead SCUC. A day-ahead partitioning framework determines zones while considering the latest system state information including scheduled outages, load forecasts, and probabilistic scenarios of renewable generation. Decomposition algorithms are also developed for SCUC to disqualify units from providing reserve on a per-scenario basis or increase the reserve quantity when congestion is likely to hinder deliverability. The dynamic reserve policies capture operational conditions better than static reserve policies since they incorporate the impacts of variable renewable resources. The results show an improvement in market surplus and a reduction in costly out of market corrections.

While it is preferred to apply stochastic programming to SCUC in order to implicitly determine the reserves, stochastic programming is still too computationally challenging. The proposed techniques complement stochastic SCUC; coupling dynamic reserve policies with stochastic SCUC reduces the scope of uncertainties that must be modeled within the stochastic program and, hence, reduces the computational burden. Dynamic reserve policies are a practical solution to improve the management of renewable resources and it opens a new realm of research techniques to address resource uncertainty in SCUC and optimal power flow problems.

II. Problem Formulation and Approach

Reserve policies are intended to ensure reserve deliverability under a wide variety of operating conditions. Changes in operating conditions, which can affect reserve deliverability, can be addressed by dynamic reserve zones that incorporate the latest information about the system operating state. It is common practice for operators to update transfer capability estimates to account for the effect of scheduled outages and the most recent load forecasts; however, it is not common to frequently update reserve zones. MISO has

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expressed interest in updating zones on a daily basis [15]; however, currently MISO only considers updating zones for adverse conditions, projected to last multiple days, which cannot be resolved through operating procedures [16]. Section III.A describes a methodology for updating zones on a regular basis to account for changing system states and to leverage the latest forecasts. The method utilizes probabilistic power flows to evaluate the effect of intermittent renewables on system operations.

It may not be practical to define zones that experience no intra-zonal congestion under any scenario, nor is it trivial to determine the optimal reserve sharing between regions. It is worthwhile to develop additional methodologies to ensure reliability outside of redefining zones. Section III.B describes alternative methodologies to mitigate congestion when zones do not efficiently guarantee reliability. This research frames a holistic portfolio of approaches for determining reliable and economical reserve requirements.

A. Dynamic Zone Determination

Updating zones on a regular basis offers additional protection against uncertainties while requiring relatively minor changes to operating procedures. Prior to SCUC, operators are aware of scheduled generation and transmission outages and have reasonable forecasts of load and intermittent generation. Some of this information may allow operators to predict what transmission bottlenecks will exist and, therefore, how to determine reserve zones.

Today, reserve zones are determined using power transfer distribution factors (PTDFs); $PTDF_{k,i}^{R}$ is the flow on transmission line *k* when injecting a MW of power at bus *i* and withdrawing a MW from a reference bus *R*. MISO and ERCOT determine zones so that injections from buses in the same zone have similar PTDFs on critical transmission paths [16]-[17]. A centrality measure based on PTDF differences (PTDFDs) is

$$PTDFD_{ij} = \frac{\sum_{k=1}^{K}\left|PTDF_{k,i}^{R}-PTDF_{k,j}^{R}\right|}{K} \tag{1}$$

where K is the number of transmission lines and $\left|PTDF_{k,i}^{R} - PTDF_{k,j}^{R}\right|$ is the absolute difference of flow on line *k* between a MW injection at bus *i* and bus *j*. The PTDFD is used to group buses that have similar impacts on transmission lines. A weighted PTDFD (WPTDFD) is used to emphasize critical lines. Applying weight w_k on transmission line *k* yields

$$WPTDFD_{ij} = \frac{\sum_{k=1}^{K} w_k\left|PTDF_{k,i}^{R}-PTDF_{k,j}^{R}\right|}{K}. \tag{2}$$

Zones may be determined using statistical clustering methods so that pairs of buses in the same zone have "small" WPTDFDs, i.e., injections from buses in the same zone have similar effects on heavily weighted lines. Large weights should be generally given to paths that represent transmission bottlenecks so that reserve can replace a random loss of power in the same zone without stressing any lines. If large weights are assigned to heavily loaded lines, then the resulting zones tend to coincide with relatively congestion-free areas separated by commonly congested paths.

The procedure to generate zones is summarized in Fig. 1. Weights are calculated using a probabilistic power flow model that simulates likely scenarios. Lines that are never congested receive the lowest weights, lines that are periodically congested receive higher weights, and lines that are consistently congested receive the highest weights. The utilization of each transmission line is tracked across scenarios and the 95th percentile is recorded. The weight assigned to a line is calculated as the square of the 95th percentile of utilization. Thus, lines that are unlikely to be congested receive low weights. The use of a high percentile gives more weight to lines with volatile flow and tends to improve robustness against severe scenarios. After the weights have been determined, a clustering algorithm is used to determine zones prior to day-ahead scheduling.

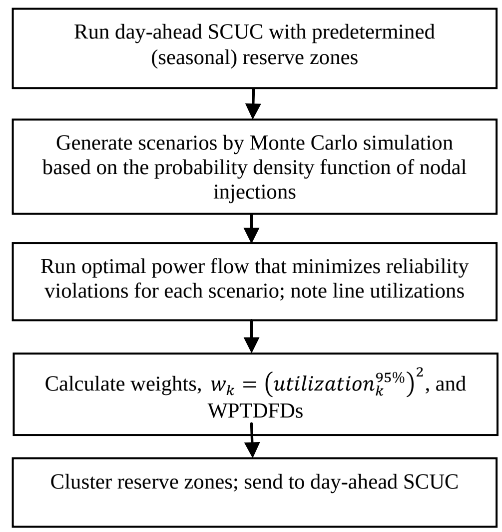

Fig. 1. Daily reserve zone determination based on probabilistic power flows.

B. Mitigating Congestion Outside of Traditional Zone Structure

The zoning methodology outlined above is innovative in that it adopts a daily probabilistic mechanism to account for potential transmission bottlenecks in order to determine reserve zones. However, reserve zones do not address intra-zonal congestion. Operators can be more conservative by procuring a reserve margin or adopting reserve downflags on a case-to-case basis to overcome intra-zonal congestion. This section describes structured approaches for defining reserve margins and reserve downflags.

We define a reserve margin as the excess reserve above the quantity needed to satisfy a target reliability threshold. Some operators will hold a reserve margin to redress generator non-performance but margins are also useful for mitigating congestion because excess reserve improves the likelihood that *enough* reserve will be deliverable.

The contingency reserve policies used in industry are diverse. PJM requires each zone to hold about 1.5 times the largest contingency [18]; WECC requires reserve to cover 6% of load plus 3% of exports [19]; ISONE requires no reserve margin; rather, reserve plus an estimate of the import capability (reserve sharing) must meet the largest contingency within a zone [20]. We propose tying the reserve margin to congestion by embedding a congestion-based stress measure directly into the reserve requirement. Additional reserve is required as congestion increases and requirements are relaxed as congestion decreases. Thus, the reserve margin is tied to the very stress that inhibits deliverability. We define the stress measure as a convex function of line utilizations, which is analogous to the performance index (PI) suggested by [21] for predicting the severity of a contingency:

$$PI = \sum_{k=1}^{K} (utilization_k)^{2n}. \tag{3}$$

A piecewise linear approximation of (3) is used to represent an individual line's contribution to the reserve requirement. A small reserve margin is procured if few lines are near their limits and a large reserve margin is procured if many lines are congested. The increasing slope of (3) discounts under-utilized lines since they are less likely to inhibit reserve deliverability.

Critical lines are not always those that are congested under normal operating conditions. It can be beneficial to predict how flows will change following a contingency or random injection fluctuation. Generation shift factors (GSFs) and line outage distribution factors (LODFs) can be used to predict how flows may change directly after a contingency occurs [21]. We borrow the same concept but estimate GSFs and LODFs with respect to an operational re-dispatch that minimizes transmission violations. By doing so, we anticipate how congestion will evolve during post-contingency re-dispatch. Reference [3] describes how to predict flow changes as part of a decomposition algorithm for SCUC.

Simply adding a reserve margin can be inefficient because additional reserve may not be located where it is deliverable. Just as important as determining proper reserve quantities, congestion-based reserve requirements endogenously reduce congestion when appropriate. Alternatively, operators will manually identify locations from where reserve is not deliverable and disallow those locations from contributing towards the reserve requirement. MISO and ISONE refer to this process as disqualifying reserves and declaring reserve downflags [22]-[23]. We propose a structured mathematical approach to determine reserve downflags. A particular flag may be appropriate for a subset of scenarios but overly conservative for others. Therefore, our approach facilitates scenario-specific reserve downflags. The autonomy of the approach accommodates changing requirements over time as necessary to reflect changing conditions. We refer to such dynamic and scenario-specific reserve downflags as generalized reserve downflags.

Fig. 2 outlines a two-stage decomposition algorithm that identifies generalized reserve downflags while solving the day-ahead SCUC problem. SCUC is initially solved using a relaxed set of downflags to obtain a solution that is economic but not necessarily reliable. Reliability analysis is then performed and flags are updated for unreliable scenarios by removing generators with undeliverable reserve. Reference [4] describes a mixed integer program used to update the reserve downflags. The updates can be viewed as reliability cuts that identify generators whose reserve may not count towards the respective requirements. Note that exact decomposition algorithms can be used to solve stochastic programs in a similar iterative fashion, e.g., Benders' decomposition. Our objective is not to solve a stochastic programming problem but to propose a fast and effective way to improve reserve requirements with a computationally efficient mechanism.

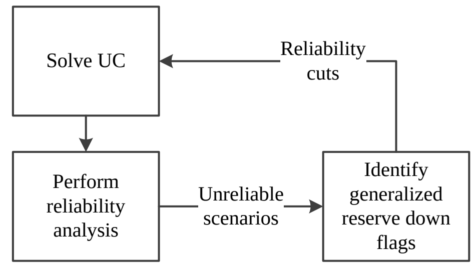

Fig. 2. Flowchart for identifying generalized reserve downflags.

III. Results

A. Dynamic Zone Determination

We compare several reserve zone methods to stochastic programming on a modified IEEE-118 bus test case with 17% wind integration described in [2]. Zone partitioning is particularly difficult because random wind fluctuations change the transmission bottlenecks. We start by analyzing two zone partitioning methods: a seasonal method and a daily method. The seasonal method mimics existing practices of ERCOT and MISO [17], [24]. Generators that have similar impacts on key transmission corridors are grouped together using a statistical clustering algorithm (K-Means [25]). The daily method is the same except that it updates zones on a daily basis.

We apply the probabilistic zone partitioning method described in Fig. 1 to incorporate information about how wind is likely to influence congestion. The zonal models are benchmarked against a scenario-based stochastic program described in [2]. Each stochastic programming instance considers 10 wind scenarios and takes an average of ten times longer to solve than the zonal models. All models require contingency reserve to exceed the largest generator and must satisfy the (3% of load) + (5% of wind) rule proposed by [26].

The zones produced by the probabilistic and traditional methods are fed into SCUC and reliability is evaluated against one thousand wind scenarios. Scenario evaluation allows violations of physical constraints when no reliable solution exists, specifically, by relaxing the node balance constraints. Table I presents the expected violation, the percentage of scenarios with violation, and the worst-case violation for any single hour. The proposed probabilistic method improves all reliability metrics and even outperforms stochastic programming on average. Although stochastic programming guarantees reliability for the 10 scenarios explicitly modeled, the probabilistic reserve zones are more robust against the total one-thousand scenarios. We also perform an N-1 contingency analysis over 10 wind scenarios and the relative performances, shown in Table II, are qualitatively similar.

TABLE I
RELIABILITY WITH WIND (MW)

Date	Seasonal[1]	Daily (Trad.)[2]	Stoch.[3]	Daily (Prob.)[4]
2-Jan	6.5 (4.7, 116)[5]	0.684 (2.1, 24)	0.12 (0.6, 13)	0.36 (1.9, 14)
9-Jan	0	0	0	0
14-Jan	6.16 (3.5, 109)	0	0.31 (1.5, 15)	0
24-Jan	8.44 (4.6, 121)	0.16 (1.2, 11)	0.16 (0.9, 11)	0
5-Feb	0	0	0.1 (0.4, 11)	0
7-Feb	0	0	0.62 (1.0, 31)	0
14-Feb	0	0	0.64 (1.1, 30)	0
22-Feb	0	0	0	0
3-Mar	5.7 (3.3, 93)	8.55 (4.2, 132)	0	0
11-Mar	12.08 (6.5, 132)	7.52 (5.4, 87)	0	0.66 (1.3, 33)
14-Mar	0	0	0	0
26-Mar	3.38 (5.2, 41)	13.68 (8.5, 127)	0	0
Ave.	3.522	2.55	0.162	0.085

[1] Traditional (seasonal) zone; [2] Traditional (daily) zone.
[3] Stochastic programming model; [4] Daily probabilistic zone model.
[5] α (β, δ); α represents the expected violation (MW), β is the percentage of scenarios with violation, and δ is the largest violation over any one hour.

TABLE II
RELIABILITY WITH WIND + CONTINGENCY (MW)

Date	Seasonal	Daily (Trad.)	Stoch.	Daily (Prob.)
2-Jan	15 (2.5, 150)	13.5 (3, 138)	25.4 (3.2, 249)	10.7 (2.2, 109)
9-Jan	14.6 (2.4, 112)	12.2 (2.4, 90)	21.6 (3, 235)	12.1 (2.3, 90)
14-Jan	11.7 (1.6, 142)	9.7 (1.5, 109)	16.8 (2.6, 235)	7.7 (1.2, 90)
24-Jan	16.8 (3, 156)	20.2 (3.2, 212)	30.2 (4.2, 270)	11.5 (2.6, 133)
5-Feb	15.6 (2.8, 183)	14 (2, 142)	31.1 (3.8, 284)	13.1 (2.2, 118)
7-Feb	15.4 (3.4, 186)	14.4 (3.2, 187)	30.3 (3.6, 280)	12.8 (3, 110)
14-Feb	15.4 (2.4, 193)	15.4 (2.4, 193)	20.1 (3, 275)	9.6 (1.6, 111)
22-Feb	12.9 (2, 145)	13 (2, 148)	20.8 (3, 287)	11.2 (1.6, 82)
3-Mar	7.7 (1.2, 108)	8.5 (1.3, 158)	8.9 (1.4, 132)	7.9 (1.4, 108)
11-Mar	11 (1.7, 157)	10.6 (1.6, 149)	11.7 (1.8, 189)	7.2 (1.2, 87)
14-Mar	11.8 (2, 171)	12.1 (2, 183)	12.7 (2, 90)	11.7 (2, 169)
26-Mar	14.1 (2.4, 142)	14 (2.4, 142)	14.8 (2.4, 166)	9.9 (1.7, 120)
Ave.	13.5	13.1	20.4	10.5

Table III combines results from Tables I and II to provide a measure of average performance. Reliability is improved by updating zones on a daily basis and reliability is further improved using the probabilistic approach. The probabilistic approach reduces the expected violation by 38% over the seasonal model. Reliability improvements are justified when operational costs are reasonable. Stochastic programming renders the lowest average operating costs and Table IV shows that costs increase 2% with the seasonal method and a further 2% using the probabilistic reserve zones. However, these costs do not account for out-of-market corrections employed in order to satisfy N-1. The probabilistic method reduces the need for corrections and is economical if the cost of out-of-market corrections exceeds $3,000 per MW of expected violation. Actual costs will vary across systems and further cost-benefit analysis is warranted on an individual basis.

TABLE III
AVERAGE EXPECTED VIOLATION (MW)

	Seasonal	Daily (Trad.)	Stoch.	Daily (Prob.)
Ave. expected violation	17.0	15.7	20.6	10.6
Improvement %	-	8.1%	-17.2%	37.8%

TABLE IV
OPERATING COST AND EXPECTED TOTAL COST (MILLION $)

Date	Seasonal	Daily (Trad.)	Stoch.	Daily (Prob.)
2-Jan	0.833	0.851	0.77071	0.87634
9-Jan	1.3884	1.3912	1.3736	1.3936
14-Jan	0.4926	0.5	0.48294	0.51265
24-Jan	0.6587	0.67476	0.63087	0.7
5-Feb	0.79933	0.79769	0.78725	0.8037
7-Feb	0.861	0.8668	0.846	0.87
14-Feb	0.63515	0.63515	0.62864	0.6724
22-Feb	0.74	0.737	0.72506	0.74225
3-Mar	0.21532	0.2137	0.2133	0.224
11-Mar	0.18775	0. 18856	0.18635	0.198
14-Mar	0.65143	0.6505	0.64801	0.65236
26-Mar	0.34462	0.34242	0.34122	0.351
Average Cost	0.651	0.654	0.636	0.666
Ave. Exp. Cost[6, 7]	0.702	0.701	0.6979	0.6977

[6] Average expected total cost is equal to the average operating cost plus the cost to correct the violations determined by the reliability evaluation.
[7] Out-of-market correction cost = $3,000/MW.

B. Mitigating Congestion Outside of Traditional Zone Structure

A modified IEEE 73-bus test case, [3], is used to compare the reserve policies. The test case is considered with and without the availability of a large baseload generator. In practice, generators may become unavailable due to scheduled maintenance or reliability problems. Absence of this particular unit leads to imports of cheap energy from neighboring parts of the system and the additional congestion significantly reduces reliability compared to normal operation.

This system exemplifies how zones can be inefficient. We use weighted PTDFDs to partition the network into two reserve zones as shown in Fig. 3. The zone interface includes a congested line and another line that is much less utilized. Operators estimate how much reserve can be shared between zones to avoid over-procuring reserve and reduce operational costs, but the transfer capability from zone *A* to zone *B* is hard to predict; physics defines the route energy takes and reserve is much more deliverable when injected at a location that prefers the lower route in Fig. 3. Uncertainty over the location of reserve in zone *A* leads to conservative reserve sharing policies that are likely to procure more reserve than necessary. This phenomenon is especially pervasive in meshed systems where the bottleneck can be hard to predict.

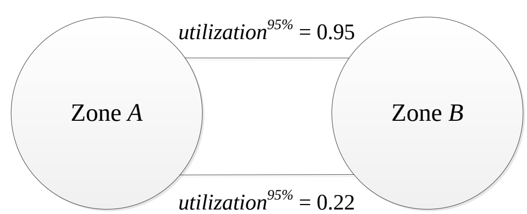

Fig. 3. Flows between reserve zones during contingency analysis.

Even though two zones is the best option for this test case, we initially limit testing to a single zone to demonstrate how reliability can be improved using only a reserve margin. Fig. 4 compares cost vs. reliability for several reserve margin policies. Policy B1 is similar to WECC and specifies that reserve must exceed a percentage of load; B2 is similar to PJM and specifies reserve must exceed a factor above the largest contingency. The congestion-based reserve margins are described in Section II.B and [3]. Each policy group is tested for various levels of conservatism; as the reserve margin becomes more conservative, cost increases and reliability tends to improve. The least conservative policies are omitted from Fig. 4 because results are similar when reserve margins are near zero. The congestion-based reserve requirements take an average of 60% longer time to solve, but tend to outperform both baseline approaches, achieving the same levels of reliability at equal or less overall cost. The congestion-based reserve requirements are particularly efficient at reducing the expected contingency violation to less than 0.05MW. This efficiency owes to the model's implicit ability to reduce congestion on critical lines, e.g., those represented in Fig. 3, when reducing congestion is more economical than procuring additional reserve.

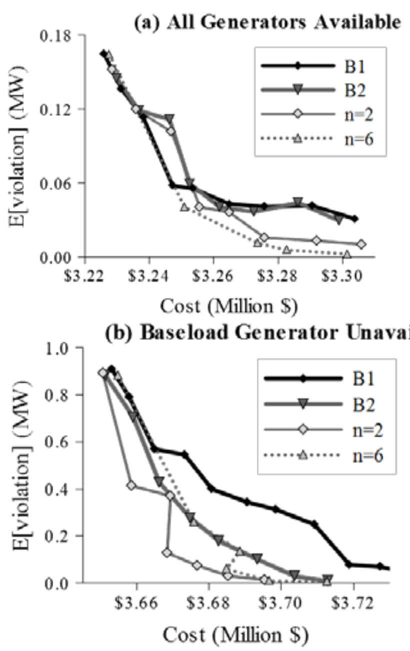

Fig. 4. Baselines and congestion-based reserve margins with n = 2 and n =6. B1 and B2 reflect the reserve policies of PJM and WECC, respectively.

Generalized reserve downflags can be more efficient than reserve margins because they implicitly limit reserve locations. Reference [4] describes a procedure to generate generalized reserve downflags for *generator* contingencies; hence, the following results consider generator contingencies only. Fig. 5 shows that reliable solutions are identified within a handful of iterations for two different load profiles. The results are more economical than applying a reserve margin (B2) and are competitive against adding a second zone. A two-zone model is tested with various levels of conservatism; conservative policies assume little reserve can be shared between zones, resulting in higher costs but more reliability. The two-zone models may not efficiently eradicate unreliability, as in Fig. 5b, because they do not account for the changes in transfer capabilities for each scenario. The benefit of generalized reserve downflags is that they disqualify reserve on a per-scenario basis. The primary downside is that multiple iterations may be needed to achieve a reliable solution. It may be necessary to define an effective set of initial reserve requirements to limit the number of iterations and make the procedure computationally feasible.

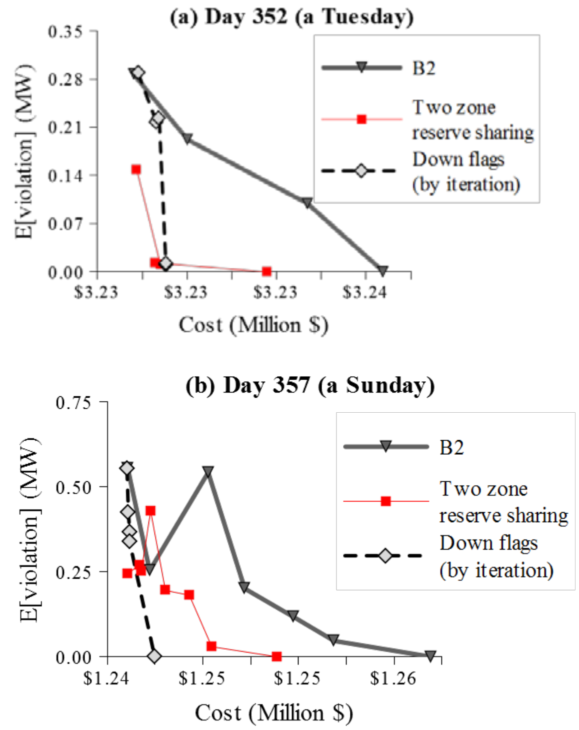

Fig. 5. Baseline single and two-zone policies and the iterative generalized reserve down procedure.

The proposed reserve policies are complementary; robust zones, based on probabilistic power flows, offer better starting points and improve reliability with little change to operating procedures. Congestion-based reserve policies improve reserve deliverability within zones by increasing reserve or decreasing congestion when the system is stressed. Generalized reserve downflags identify locational requirements for specific scenarios. The greatest potential exists when combining these policies to leverage their individual strengths.

IV. Conclusions

Transmission constraints threaten to make reserves unavailable for contingency response. Zonal requirements ensure local reserves and, thus, improve the likelihood that the reserve is deliverable; however, traditional zones do not adapt to the changing operating conditions that increasingly characterize the grid. We have described several novel reserve policies that improve efficiency and reliability. A probabilistic framework is used to incorporate uncertainty (load and renewables) into zone partitioning. A congestion-based reserve margin acquires additional reserve or reduces congestion on critical lines when the system is stressed. Finally, generalized reserve downflags disqualify reserve from targeted locations on a per-scenario basis. Testing on IEEE test cases demonstrates the potential for each approach to improve reliability across a range of scenarios efficiently. This research also addresses the oft-made assumption that intra-zonal reserves are perfectly deliverable. These innovations are well-timed to address the growing day-to-day uncertainties that exist in the power grid and the proposed reserve policies open new opportunities to further refine and improve reserve requirements for real-time, hour-ahead, and day-ahead scheduling problems. This will improve our management of variable renewable resources, contingencies, and other uncertain events. The proposed mechanisms are practical since they are computationally efficient, improve reliability, and improve economic efficiency.

V. Future Work

Stochastic programming is not used today for SCUC due to computational challenges. Future work will further refine the proposed reserve policies and combine them with stochastic SCUC algorithms to achieve two transformative benefits that address this *research gap*: a) robust reserve zones (the daily probabilistic zone model) substantially reduce the number of scenarios that require stochastic treatment and b) embedded dynamic reserve policies greatly improve the convergence of stochastic SCUC. The proposed techniques produce novel offline and embedded dynamic reserve policies, which will bring stochastic SCUC to the market sooner by improving computational efficiency, scalability, and economic efficiency. Furthermore, the proposed reserve policies will greatly enhance existing operations by improving our management of uncertainties and increasing the maximum penetration level of intermittent renewable resources.

VI. Acknowledgment

The authors gratefully acknowledge Professor Muhong Zhang, of Arizona State University, for her contributions to the related publications.

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VIII. Biographies

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Probabilistic Simulation Methodology for Evaluation of Renewable Resource Intermittency and Variability Impacts in Power System Operations and Planning (3.4)

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***Abstract*—We report on the development of a comprehensive, stochastic simulation approach for power systems with renewable and storage resources operating in a competitive market environment. The approach explicitly represents the uncertain and time-varying natures of the loads and supply-side resources, as well as the impacts of the transmission constraints on the hourly day-ahead markets. We adopt Monte Carlo simulation techniques to emulate the side-by-side power system and transmission-constrained hourly day-ahead market operations. The approach quantifies the power system economics, emissions and reliability variable effects. We address the implementational aspects of the methodology so as to ensure computational tractability for large-scale systems over longer periods. Applications of the approach include planning and investment studies and the formulation and analysis of policy. We illustrate the capabilities and effectiveness of the simulation approach on representative study cases on a modified *IEEE* 118-bus test system. The results provide valuable insights into the impacts of deepening penetration of wind resources.**

I. Introduction

Renewable resources, such as wind and solar, are widely viewed as clean sources of energy with virtually zero fuel costs and emissions. However, renewable resource generation outputs are highly variable, intermittent and only controllable by the operator to a limited extent. The variable/intermittent nature of the wind speeds, for example, presents major challenges in the integration of wind resources as the wind may fail to blow when the system actually needs the wind generation output [1], [2], [3]. Indeed, a frequent phenomenon in many regions with wind resources is the pronounced output of wind generation, due to the appropriate wind speeds, in the low-load hours and rather low or near zero outputs, due to the low wind speeds, during the peak-load periods. Such a misalignment of the wind generation and load patterns, coupled with the limited controllability over wind resources, implies that the full potential of grid integrated wind resources may not be realized. Moreover, there are concerns about the ”spilling” of wind energy during low load conditions due to the insufficient load demand and the physical impossibility to shut down the base-loaded units for short time periods.

A basic mechanism that system operators use to manage the integrated renewable generation variability and intermittency is to increase the reserve levels [4]. Such operational tactics, typically, lead to increases in both the overall production costs and the emissions, notwithstanding the zero fuel costs and emissions of the renewable resources. It is precisely such situations that can advantageously exploit the flexibility of utility-scale storage resources to improve the utilization of the renewable resources [5]. Storage resources may be used, for instance, to store wind energy whenever produced and release it during peak-load hours so as to displace the costly energy from polluting generating units. While storage resources are highly costly investments, their effective management – charge-discharge schedule and operations – impacts considerably the total production costs since they influence the variable portion of the costs [6]. A particularly acute need is a practical simulation tool that can reproduce, with good fidelity, the expected variable effects in systems with renewable and storage resources. Such a tool has myriad applications to power system planning, operations, investment analysis, as well as policy formulation and assessment.

We report on the development of a stochastic simulation approach with the ability to take explicitly into account the market structure, the various sources of uncertainty – including the renewable resource generation output variability/intermittency –, the coordinated operation of multiple integrated storage units controlled by the independent system operator (*ISO*), and the impacts of the transmission constraints on the deliverability of the electricity to the loads in the evaluation of the expected production costs, expected emissions and reliability indices. The conventional probabilistic simulation approach, based on the load duration curve model, is unable to represent the transmission constraints, nor capture the inter-temporal effects required in the simulation of the renewable and storage resources. The representation of such features requires that the demands and resources be modeled as random-processes. Our methodology incorporates such random-process-based models and so is capable to account for the spatial and temporal correlations among the demands and among the renewable resource generation outputs at the various sites. We have developed a storage scheduler to assist with the decisions to determine the participation of each storage unit in the

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markets over time, in coordination with the demands and available supply-resources, and with the inter-temporal system operational constraints fully considered. The storage scheduler takes full advantage of arbitrage opportunities in the operations of the multiple storage units over the specified scheduling period.

The approach uses an hour as the smallest indecomposable unit of time and uses the realizations of the random processes at these discrete sub-periods. In addition, a snapshot representation of the grid is used to represent the impacts of the transmission constraints on the hourly day-ahead markets (*DAM*s). The simulation methodology – based on the deployment of Monte Carlo simulation techniques – uses systematic sampling mechanisms to compute the realizations of the various random processes and to construct the so-called *sample paths*. The procedure entails sampling the probability distributions associated with the demands and supply-side resource random processes to generate the *input* sample paths that we use to drive the emulation of the hourly *DAM* clearings. The market clearing results are obtained by determining the solution of an optimal power flow [7], [8]. We collect such market outcomes so as to construct the *output* sample paths from which we estimate the various economic, emission and reliability metrics. These metrics include the hourly expected locational marginal prices (*LMP*s), congestion rents, supply-side revenues, wholesale purchase payments, either energy charged into or discharged by storage, and the emissions, as well as the *LOLP* and *EUE*. From the hourly values, we then determine the values for the simulation periods, which are then used to determine the metric values for the study period. The methodology is able to capture the seasonal effects in loads and renewable resource generation outputs, the impacts of maintenance scheduling and the ramifications of new policy initiatives. For the performance of various policy studies, we also provide weekly unit commitment schedules that allow the user to specify the weekly reserves requirements. These features are essential in the analysis of the substitutability of conventional generation by renewable resources and storage technologies under deepening penetration levels. We have also devoted much attention to ensure the computational tractability of the tool so as to allow the simulation over longer-term periods. As such, there is a broad range of applications of the simulation methodology to planning, investment, transmission utilization and policy formulation and analysis studies for systems with integrated renewable and storage resources. A very useful feature of the tool is the ability to quantitatively assess the impacts of deepening penetration of wind and storage technologies.

The body of the paper contains four more sections. In section II, we describe the overall simulation methodology. In section III, we provide illustrative case studies to demonstrate the capabilities of the approach in the investigation of the impacts of deepening wind penetration in systems with integrated storage resources. We conclude with a summary and directions for future work in sections IV and V respectively.

II. Approach/Methods

We devote this section to describe the simulation framework and approach. The simulation is performed for the specified study period, which we decompose into non-overlapping simulation periods. We define each simulation period in such a way that the system resource mix and unit commitment, the transmission grid, the operating policies, the market structure and the seasonality effects remain unchanged over its duration. For the competitive market environment, the natural choice for a simulation period is a week. This choice captures the weekly load (demand) pattern and easily incorporates the scheduled maintenance outages. We further decompose each simulation period into subperiods of an hour, with a subperiod being the smallest indecomposable unit of time represented in the simulation, as shown in Fig. 1. The simulation, as such, ignores any phenomenon whose time scale is smaller than an hour, and we assume that the value of each variable is constant over the hour. The proposed approach is, however, sufficiently general to allow higher or lower resolution if desired.

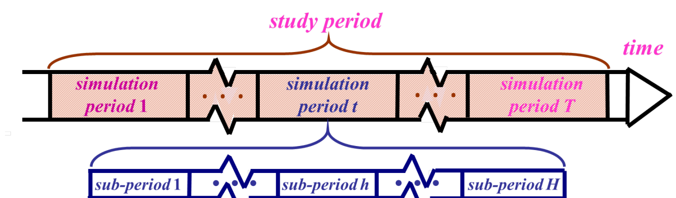

Fig. 1: Conceptual representation of the adopted time framework

To simulate the side-by-side power system and transmission-constrained market operations, we emulate, in each simulation period, the sequence of the 168 hourly *DAM* clearings to determine the hourly market outcome contributions to the performance metrics of interest. We use the hourly discretized time axis in the representation of the variables and evaluate the metrics on an hourly basis. The modeling of the uncertainty in the highly variable demands, renewable resource outputs, conventional generator available capacities and, as a consequence of the market economics, storage resource outputs/demands, is in terms of discrete-time random processes (*r.p.*s), which in this work, are collections of random variables (*r.v.*s) indexed by the 168 hours of the simulation period. These *input r.p.*s are mapped by the *DAM* clearing mechanism into the *output* discrete-time *r.p.*s, as illustrated in Fig. 2. Such output *r.p.*s, whose collections of *r.v.*s are also indexed by the 168 hours of the simulation period, represent the market outcomes. We call a *sample path* (*s.p.*) a collection of time-indexed realizations of the *r.v.*s that define the *r.p* [9]. We note that a *s.p.* intrisically captures the auto-regressive time-series structure of the *r.p.*.

Our simulation uses the so-called *independent Monte Carlo* technique [10], and requires the construction of multiple *independent and identically distributed* (*i.i.d.*) *s.p.*s for each output *r.p.* to estimate the performance metrics [1]. Each simulation

[1] Note that in this context, the phrase "*i.i.d. s.p.*s" has the sense that the *s.p.*s constitute the realizations of independent identically distributed *r.p.*s

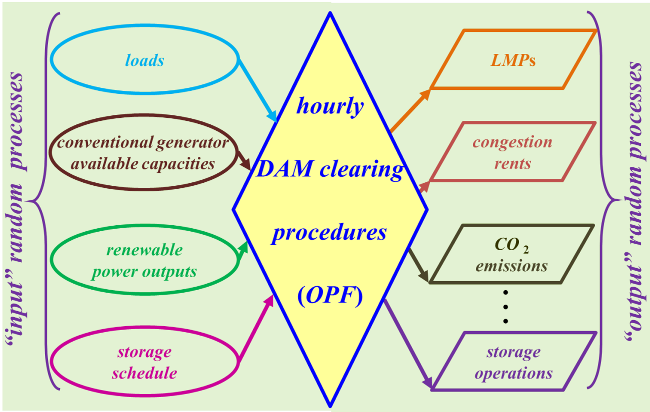

Fig. 2: Conceptual structure of the simulation approach

run constructs a *s.p.* for each output *r.p.*s. The construction proceeds as follows: sample paths of the input *r.p.*s, obtained by sampling the input *r.p.* joint cumulative distribution functions (*j.c.d.f.*s), are mapped into *s.p.*s of the output *r.p.*s by the market clearing mechanism model [7], [8] for each hourly *DAM*. The hourly market outcomes of interest include the locational marginal prices (*LMPs*), the total wholesale purchase payments, the total supply-side revenues, the total congestion rents, CO_2 emissions, the loss-of-load events and associated unserved energy.

We carry out multiple simulation runs in order to create the output *s.p.*s from which we estimate our performance metrics. We select our performance metrics to be the expected values of the time-indexed *r.v.*s whose collection is the output *r.p.* of interest. In practice, we make use of the collected *i.i.d. s.p.*s to estimate, for a given output *r.p.*, the sample mean point estimate of each constituent, time-indexed *r.v.*. The number of simulation runs is chosen to ensure that the estimation of a given expected value falls within a pre-specified confidence level interval [11].

We briefly discuss the stochastic models for the input *r.p.*s and their use in the Monte Carlo simulation in the following order: demands, renewable resource generation outputs, conventional generator available capacities and storage outputs/demands. Note that we make the widely-used assumption that the stochastic models for the demands, renewable outputs and conventional generator available capacities are statistically independent of each other. Storage on the other hand, is highly dependent on the loads and other supply-resources.

From the outset, we wish to capture the spatial and temporal correlations among the various buyer demands. Now, given that the cleared demands, as observed from historical load data, are seasonal and have a weekly cycle, we assume that, in each week of the same season, the buyer demands over a week period can be modeled by a discrete-time *r.p.*, whose random vectors of buyer demands are indexed by the 168 hours of the week. Such representation explicitly accounts for the correlations across buyer and time that exist among the constituent *r.v.*s that correspond to the hourly demands of each buyer over a one-week duration. We construct the *j.c.d.f.* of the hourly buyer demand *r.p.* by gathering weeks of hourly buyer demands from a seasonally disaggregated historical database. In terms of the Monte Carlo method, such *j.c.d.f.* may be directly sampled to yield a *s.p.* whose collection of hourly realizations determines the maximum demand bid by each buyer in the associated hourly *DAM*s.

We apply a similar approach to the stochastic modeling of the multi-site renewable resource generation outputs. The following method is well adapted to the modeling of multi-site wind or solar power outputs for example. To make the explication of the model concrete, we limit our discussion to the treatment of the *r.p.*s used to model the wind speeds/power outputs. We assume that each wind speed at each farm location is uniform for the entire farm. Furthermore, we assume that the wind speeds are seasonal and have a daily cycle. In a similar manner as with the hourly buyer demands, we seek to capture the spatial and temporal correlations of the wind speed *r.v.*s across locations and hours of the day. Thus, we represent the multi-site hourly wind speeds by a discrete-time *r.p.*, whose random vectors of wind farm wind speeds are indexed by the 24 hours of the day. The construction of such a discrete-time *r.p.* closely follows that of the hourly buyer demand *r.p.*. In the specific case of the multi-site hourly wind speed *r.p.* however, we need to generate 7 daily *s.p.*s in order to construct the *s.p.* for the 7×24 hours in a week. This may done by sampling and juxtaposing 7 independent *s.p.*s from the *j.c.d.f.* of the multi-site wind speed *r.p.*. The result is a week-long wind speed *s.p.* that is then converted into the corresponding wind power output *s.p.* via the use of wind farm characteristic power curves [12]. The collection of hourly wind power output realizations contained in the week-long sample path is used to determine the wind power output quantities offered in the associated hourly *DAM*s.

We model each conventional resource as a multi-state unit with two or more states – outaged, various partially derated capacities and full capacity. We assume that each conventional resource is statistically independent of any other generation resource. We use a Markov chain model with the appropriate set of states and transition intensities to represent the underlying *r.p.* governing the available capacity of each conventional resource [13]. We assume statistically independent exponentially-distributed *r.v.*s. to represent the transition times between the states. Such model allows us to explicitly represent the periods during which a conventional unit might be up, down, or running at derated capacities in the simulation. The methodology for simulating the available capacity of a conventional resource over time is well documented in the literature, and can be found under the names of *next-event method* [14], *state duration sampling* [15], or simply *sequential simulation* [16], [17]. In terms of our approach, the state of a seller resource, i.e., its available capacity, is thus determined for each hour of the week. The collection of hourly realizations constitutes a week-long *s.p.* of a seller resource available capacity. We use the hourly realizations of such a *s.p.* to determine the resource maximum output quantity offered in the associated hourly *DAM*s.

The characterization of the storage unit participations in the hourly *DAM*s is a function of the demands and supply-side resources. As such, the analytical description of the associated *r.p.* is quite involved. The construction of associated *s.p.*s is, however, quite manageable. To this end, we have developped a storage scheduler to determine how each storage unit should behave in the hourly *DAM*s of a given scheduling period. Since the storage units are assumed to be controlled by the *ISO*, the objective of the storage scheduler is to maximize the sum of the hourly social surpluses as determined by the outcomes of the hourly *DAM*s. The storage scheduler solves a "look-ahead" multi-period *OPF* that uses plausible realizations of the buyer demands and supply-side resource available capacities in each hour of the scheduling period to "optimally" coordinate the storage unit operations. The inter-hour constraints imposed by storage dynamics are explicitly represented so as to produce schedules that are chronologically consistent. The generated schedules consist of the hourly status of each storage unit (discharge, charge, idle) as well as the associated charged/discharged energy. They provide the appropriate information for the emulation of the hourly *DAM*s. We view a storage schedule as the basis for creating a *s.p.* associated with the storage unit participations in the hourly *DAM*s. As such, a storage schedule forms the input *s.p.* that is used to determine the storage unit maximum outputs offered/maximum demands bid in the hourly *DAM*s.

To be of practical value, we focused on the implementational aspects of the simulation approach so as to improve its computational tractability. A first step is the judicious selection of the number of simulation periods to be simulated. We take advantage of the fact that several weeks in a season have similar load (demand) shapes and renewable generation output patterns. We select a representative week among them for simulation and weigh the results by the number of weeks it represents. This way, we reduce the number of simulation periods and cut down the computational efforts. Our extensive testing indicates that, for regions with four distinct seasons, 14-18 representative weeks suffice to cover a year.

Another measure to reduce the computational burden is to systematically "warm-start" the storage scheduler runs and the market clearing optimizations.

We also have studied in depth a wide range of *variance reduction techniques*. Our findings indicate that only the control variate technique [18] is effective in bringing about significant variance reduction. The use of the hourly aggregated available generation capacity, i.e., the sum of conventional resource and renewable available capacities, as a control variate in each hour h of the simulation period can reduce computations by 50% for some of the metrics, particularly for the economic ones. However, the control variate scheme performs poorly in the evaluation of the reliability indices due to the weak correlation observed in practice between the control variate and the hourly total unserved energy.

A further step to improve the computational tractability is the parallelization of the simulation of each representative week on dedicated cores/computers. Parallelization of the simulation runs themselves – within the Monte Carlo simulation of each representative week – is in theory achievable achievable, since all simulation runs are independent from one another (in the sense of *independent Monte Carlo* as defined in II).

III. Simulation Results

We performed extensive testing of the simulation approach and illustrate its application with two representative studies carried out on a modified *IEEE* 118-bus test system [19] using scaled *ISO* load data for the year 2007 [20] and historical wind data from the *ISO* geographic footprint [1]. In these case studies, we scale the load data so that the annual peak load is 8,300 *MW*. The 99 conventional generation units of the test system have a total nameplate capacity of 9,914 *MW*. The system incorporates 4 wind farms, whose wind turbine characteristics, including power curves, are collected from *NREL* wind integration studies [1]. The aggregated nameplate capacity of wind power amounts to 2,720MW (unless otherwise specified), about 30% of the annual peak load, and is equally distributed among the 4 wind farms. We assume that each buyer bids his/her load as a *fixed* demand in each hourly *DAM*s. We use the estimated marginal costs of the generating units as offering prices throughout the simulations. Owing to the fact that wind power has no fuel cost, we assume that wind power is offered at 0 *$/MWh*. We limit our analysis to a single year in order to gain insights into the nature of the results obtained. Taking into account the seasonality effects, as well as the maintenance schedules of the conventional generation units, we select 16 representative weeks out of the 52 weeks of the year. We perform a unit commitment for every one of the 16 representative weeks so as to maintain the desired reserve margins (15% of weekly peak load unless otherwise specified). For the test system, our extensive numerical studies indicate that beyond 100 simulation runs, there is too little improvement in the statistical accuracy of the economic and emission metrics to warrant the extra computing-time needed for the execution of additional simulation runs. The computation of the reliability metrics, however, required about 500 simulation runs, owing to the fact that our test system is relatively reliable and the loss of load events constitute rare occurences.

In the first case study, we examine the power system behavior under deepening wind penetration: from 0 *MW* total nameplate capacity in the base case to 2,720 *MW*, using increments of 680 *MW*. Each case is evaluated with and without storage resources. In the no storage cases, the supply-side resources consist only of the 99 conventional generation units and the 4 wind farms with the 15% reserves margin provided solely by the conventional units. In the storage cases, the system has a single storage unit with 400 *MW* capacity, 5,000 *MWh* storage capability and a round-trip efficiency of 0.89. The 15% reserves margin is met by both the conventional units *and* the storage unit. As the wind penetration deepens, the overall wholesale purchase payments and CO_2 emissions are reduced, while there are rather marked improvements in the system reliability indices, as shown in Fig. 3 and Fig. 4 respectively.

However, it is also clear from these plots that the reductions and improvements are characterized by diminishing returns as the wind penetration deepens. Results show that such phenomenon may be partially offset with the integration of the storage unit. Overall, storage works in synergy with wind to

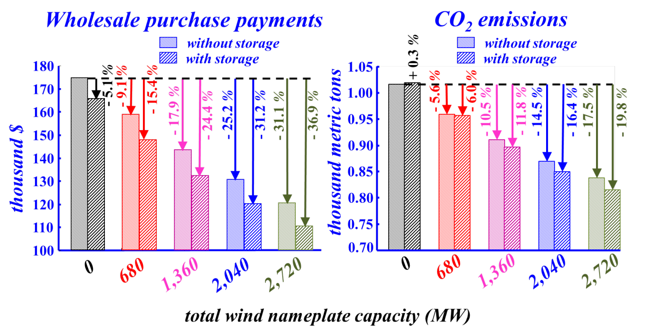

Fig. 3: Expected hourly total wholesale purchase payments (left) and CO_2 emissions (right)

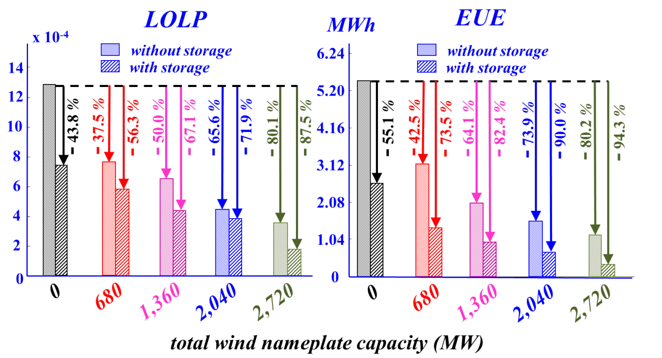

Fig. 4: Annual reliability metrics

drive further down wholesale purchase payments and improve system reliability. On the other hand, CO_2 emissions are not significantly affected by the integration of a storage unit. We attribute this result to the fact that CO_2 emissions largely depend on the relative utilization of the various fossil-fuel fired units. In a system where the nameplate wind capacity does not exceed the system base load, the storage unit draws its energy from base-loaded fossil-fuel fired units. Its impact on CO_2 emissions are due to the differences in the emission rates of the base-loaded fossil-fuel fired units from which it charges, versus those of the peaking units that it displaces upon discharge. In our system, the base-loaded units tend to be slightly more polluting than their peaking counter-parts, hence the slight increase in CO_2 emissions seen in the absence of the wind resources. As wind penetration levels increase, however, the relative utilization of the fossil-fuel fired units differs due to the higher prevalence of wind variable outputs.

In the second case study, we investigate to what extent a combination of wind and storage resources may substitute for conventional resources from purely a system reliability perspective. The base case with no wind and storage resources evaluates the system *LOLP* and *EUE* for a 15% system reserves margin. In all the other cases, the conventional resource mix is supplemented by the 4 wind farms with a total nameplate capacity of 2,720 *MW* and 4 identical storage units, each with 100 *MW* capacity, 1,000 *MWh* storage capability and 0.89 round-trip efficiency. In these cases, the reserves are provided by the conventional *and* storage resources and we examine the impacts of progressively retiring some conventional resources, thus decreasing reserves margin levels.

Figure 5 shows the $LOLP$ and EUE as a function of the system reserves margin levels (the studies here have been carried out for one particular representative week).

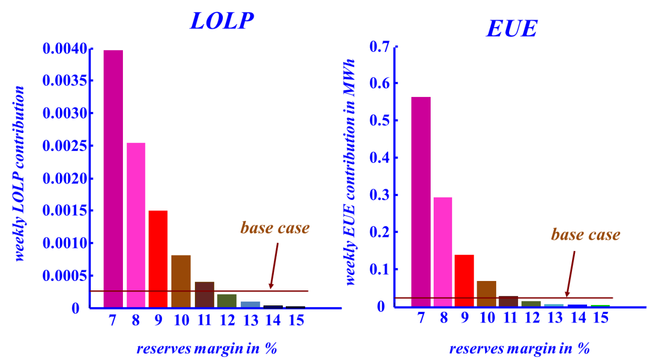

Fig. 5: Weekly *LOLP* and *EUE* versus system reserves margins

The simulation results indicate that the 2,720 *MW* of installed wind capacity – about 30% of the peak load (8,090 *MW*) – can substitute for about 300 *MW* of retired conventional generation capacity – about 3.7% of peak load. Absent storage units, with all other conditions unchanged, the 2,720 *MW* wind can replace only about 220 *MW* of retired conventional generation capacity – about 2.7% of peak load. While the wind resources by themselves prove to be poor substitutes for retired conventional resources from a reliability perspective, the integration of the 400 *MW* of total storage capacity – about 4.8% of peak load – increases the wind resource capability to substitute for conventional resources by an additional 1% of the peak load. This result indicates that wind and storage resources can work synergystically.

IV. Conclusion

In this paper, we present the comprehensive, stochastic simulation framework we developed to emulate the side-by-side behavior of power system and market operations over longer-term periods. Our approach makes detailed use of discrete-time *r.p.*s in the adaptation of Monte Carlo simulation techniques. As such, the framework can explicitly represent various sources of uncertainty in the loads, the available capacity of conventional generation resources and the time-varying, intermittent renewable resources, with their temporal and spatial correlations. In addition, the simulation methodology represents the impacts of the network constraints on the market outcomes. In this way, the simulation approach is able to quantify the impacts of integrated intermittent and storage resources on power system economics, reliability and emissions. The stochastic simulation approach has a broad range of applications in planning, operational analysis, investment evaluation, policy formulation and analysis and to provide quantitative assessments of various what if case studies.

The representative results we present from the extensive studies performed effectively demonstrate the strong capabilities of the simulation approach. The results of these studies on a modified *IEEE* 118-bus system, making use of scaled *ISO* load data and historical wind data in the *ISO* geographic footprint clearly indicate that energy storage and wind resources tend to complement each other and the symbiotic effects reduce wholesale costs and improve system reliability. In addition, we observe that emission impacts with energy storage depend on the resource mix characteristics. An important finding is that storage seems to attenuate the ”diminishing returns” associated with increased penetration of wind generation. The integration of storage capacity can also enhance, to some limited extent, the wind resource poor capability to substitute for conventional resources from purely a system reliability perspective.

The development of the approach provides a practical implement for the simulation of large-scale power systems with integrated renewable and storage resources. As the deepening penetration of renewable resources becomes reality, the interest in exploiting the flexibility afforded by utility-scale storage resources increases. Such developments create myriad opportunities for the effective deployment of the stochastic simulation methodology to provide the quantitative answers to a broad array of questions that need to be answered in the planning, operations and analysis of the integration of these resource additions. The ability to provide the needed answers will be further testimony of the valuable contribution brought about by the developed simulation methodology.

V. Future work

The generality of the framework serves as a useful basis for the simulation of the integration of other time-varying and intermittent renewable resources as they become more economic. Examples include concentrated solar plants, tidal power projects and offshore wind farms. In addition, the deeper study of symbiotic interactions between demand response and renewable resources needs to be investigated. The deeper penetration of renewable resources gives rise to critical operational problems that need to be addressed. One such problem is the additional impacts of the variable energy resources on the utilization of the conventional units. In particular, ramping capability requirements in the grid becomes a major issue. The simulation methodology may be extended to provide useful insights into the systematic specification of such requirements. Efforts on this topic will be of considerable interest to industry and will be reported in future papers.

VI. Access to products

The developed methodology and the implementation software will be available on the website of George Gross (http://energy.ece.illinois.edu/GROSS). Also, on that website relevant publications and theses are available for downloading.

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Direct and Telemetric Coupling of Renewable Power Resources with Deferrable Load (3.1)

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***Abstract*—We present a stochastic unit commitment model for assessing the reserve requirements resulting from the large-scale integration of renewable energy sources and deferrable demand in power systems. We use a scenario selection algorithm inspired by importance sampling for reducing the representation of uncertainty and a Lagrangian relaxation decomposition algorithm for solving the problem. We present three alternative demand response paradigms for assessing the benefits of demand flexibility in absorbing the uncertainty and variability associated with renewable supply: centralized co-optimization of generation and demand by the system operator, demand bids and coupling renewable resources with deferrable loads. We present simulation results for a model of the Western Interconnection.**

I. Introduction

This report presents a model for assessing the benefits of demand-side flexibility on absorbing the variability and uncertainty of renewable supply. In the report we consider three fundamental approaches for modeling flexible demand [1]. At the fully centralized end, we consider the case where the system operator centrally co-optimizes the dispatch of demand-side resources, renewable supplies and generators. This is unrealistic in practice as the system operator operates the system at a bulk scale and cannot enforce control on the system down to the retail level. In addition, the optimization problem at hand is too complex to solve. Nevertheless, this ideal model provides a benchmark for the potential benefits of demand flexibility. Sioshansi [2] considers this model in a deterministic setting. We extend this approach to account for the uncertainty introduced by renewable energy supply. A fully decentralized approach for coordinating demand response that we also consider in this report is to establish real-time pricing at the retail level. This possibility was introduced by Schweppe et al. [3] and is discussed by Borenstein et al. [4]. The common approach of reasoning about real-time pricing in the power system economics literature is the use of decremental demand bids. Sioshansi and Short [5] use this approach in the context of a unit commitment model. Borenstein and Holland [6] and Joskow and Tirole [7], [8] also use this approach for analyzing retail pricing. However, there is strong institutional opposition to this approach as it exposes retail consumers to the volatility of electricity prices. In addition, real-time prices often fail to convey the economic value of demand response due to the non-convex operating costs of system operations. This effect has been reported by Sioshansi [5]. Moreover, demand-side bidding fails to capture the cross-elasticity of deferrable demand over time. An intermediate approach for integrating demand response that we consider in this report is coupling the operations of renewable resources with deferrable demand. The motivation of coupling renewable generation with deferrable demand is to create a net resource that appears “behind the meter” as a virtual power plant from the point of view of the system operator.

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In order to accurately assess the impacts of renewable energy and demand response integration on power system operations it is necessary to represent the balancing operations of the remaining grid by using a unit commitment model of the daily scheduling and dispatch procedure performed by the system operator. In this report, a stochastic formulation of the unit commitment model is used in order to quantify the level of reserves that are required in order to integrate renewable resources reliably and the contribution of demand response in mitigating these requirements. The fact that a unit commitment model can accurately represent the balancing operations of the system has resulted in numerous renewable integration studies based on unit commitment, including Ruiz et al. [9], Sioshansi and Short [5], Wang et al. [10], Contantinescu et al. [11], Tuohy et al. [12], Morales et al. [13], Bouffard et al. [14]. The model presented in this report is discussed in detail by Papavasiliou et al. [15] and Papavasiliou and Oren [16].

Despite the fact that stochastic unit commitment is appropriate for quantifying the impacts of renewable energy and demand response integration, the model introduces challenges in terms of representing uncertainty and solving the resulting large-scale mixed integer linear program. Dupacova et al. [17] pioneered scenario selection and scenario reduction algorithms motivated by stability results on the optimal values of stochastic programs with respect to perturbations in probability measures. Faster variants of these algorithms were presented by Heitsch et al. [18] and their effectiveness in the stochastic unit commitment problem was demonstrated by Gröwe-Kuska et al. [19]. As a result of this work, this class of algorithms was subsequently adopted in the stochastic unit commitment literature. Among the wind integration studies referenced above, the algorithms of Heitsch et al. [18] are used by Tuohy et al. [12] and Morales et al. [13]. Although these algorithms can be applied in a straightforward fashion for the case of renewable integration studies without transmission constraints, they may underestimate the severity of certain scenarios [15].

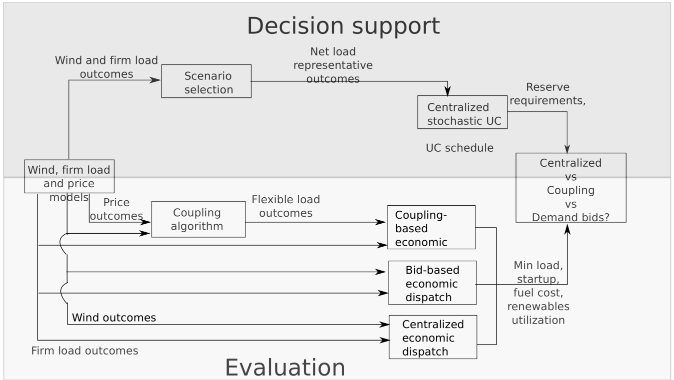

Fig. 1. Overview of the model.

Furthermore, it is not clear how they can be used for selecting and weighing scenarios of multi-area renewable production multiplexed with composite element (generator and transmission line) outages [16]. In order to address these challenges, Papavasiliou and Oren [16] propose a scenario selection and weighing algorithm inspired by importance sampling that is also used in this report. According to the proposed algorithm, scenarios are selected according to their effect on the expected cost and weighed such that their selection does not bias the objective function of the stochastic unit commitment formulation. In order to address the size of the resulting large-scale mixed integer linear program, the decomposable structure of the problem can be exploited. Decomposition algorithms based on Lagrangian relaxation for the stochastic unit commitment problem were pioneered by Takriti et al. [20]. Alternative relaxations were subsequently presented by Carpentier et al. [21] and Nowak and Römisch [22]. Shiina and Birge [23] presented an alternative decomposition approach for solving the stochastic unit commitment problem using column decomposition. In Papavasiliou et al. [15] and Papavasiliou and Oren [16] the authors present a dual decomposition algorithm for solving the problem that is also used in this report.

The remaining report is organized as follows. In Section II we provide an overview of the components of our model. In Section III we describe in detail the demand flexibility models that we consider in our analysis. Results from a test case of the Western Interconnection are presented in Section IV. In Section V we discuss the conclusions of our work.

II. Model Overview

The modeling approach adopted in this report follows a two-stage stochastic formulation proposed by Ruiz et al. [24]. Generators are partitioned in a set of slow resources that need to be committed in the day-ahead time frame and a set of fast generators that can be committed and dispatched in real time, after uncertainty in the system has been revealed. In Fig. 1 we present a diagram for integrating demand response models with the unit commitment and real-time dispatch model. The *decision support* module is a stochastic unit commitment model that determines the day-ahead unit commitment schedule of slow generation resources, while accounting for the randomness of renewable supply and firm (inflexible) demand. Given the day-ahead schedule determined by the stochastic unit commitment model, we evaluate the performance of various demand response strategies in the economic dispatch phase, represented by the *evaluation* module.

A. Statistical Models

The analysis is driven by uncertainty in renewable supply, firm (inflexible) demand, and real-time prices. We use a second order autoregressive time series model for representing wind speed. A static power curve is used for converting wind speed to wind power production. Our calibration and simulation methodology follows Brown et al. [25], Torres et al. [26] and Callaway [27]. The calibration and simulation procedure follows the steps outlined in Papavasiliou and Oren [16]. The fit of the wind model to the available data is presented in Papavasiliou and Oren [16]. Firm demand is also modeled as a second order autoregressive process, assumed to be independent of renewable production.

B. Stochastic Unit Commitment

In order to determine the day-ahead reserves that are committed by the system operator in order to accommodate the simultaneous integration of renewable supply and deferrable demand, we formulate a unit commitment model that assumes that the system operator co-optimizes the dispatch of flexible loads and generation resources. The model follows the formulation in Papavasiliou et al. [15]. An integral constraint can be introduced to the stochastic unit commitment model that represents the need to supply a total of R units of energy to deferrable loads within the horizon T:

$$\sum_{t \in T} e_{st} = R, s \in S, \tag{1}$$

where S is the set of scenarios and e_{st} is the amount of energy supplied to deferrable loads in scenario s, period t.

III. Demand Flexibility

As we discuss in Section I, we consider three fundamental approaches for modeling demand flexibility. In a fully decentralized approach, price-responsive loads bid valuations and demand flexibility is introduced in the objective function of the problem. Decision variables for such price-responsive loads are denoted by d_{lt}. In a fully centralized approach, demand flexibility can be accounted for explicitly by the system operator and is introduced in the problem through constraints rather than through the objective function. In this case the system operator controls loads directly through decision variable e_t while respecting their operating constraints. Coupling represents an intermediate approach where deferrable loads coordinate their consumption with renewable suppliers in order to appear "behind the meter" from the point of view of the system operator.

A. Centralized Load Control

In the centralized load control approach we assume that the system operator co-optimizes the dispatch of flexible loads and generation resources. The formulation of the centralized load control model is obtained from the economic dispatch model by enforcing $d_{lt} = 0$ for all loads l and periods t. The net demand D_{st} in the market clearing constraint represents the difference of random firm demand and random renewable supply.

B. Demand Bids

The demand model that we present in this section is based on Borenstein and Holland [6] and Joskow and Tirole [7], [8]. We assume a linear demand function that consists of a fraction α of inflexible consumers who face a fixed retail price λ^R, and a fraction $1 - \alpha$ of price-responsive consumers who face the real-time price of electricity λ_t. The demand function $D_t(\cdot)$ for each period can therefore be expressed as:

$$D_t(\lambda_t; \omega) = a_t(\omega) - \alpha b \lambda^R - (1 - \alpha) b \lambda_t, \qquad (2)$$

where ω represents an element of the sample space that determines the realized inflexible demand, $a_t(\omega)$ is the intercept and b is the slope of the demand function. Note that we assume a common slope for all time periods and a time-varying stochastic intercept that depends on the realization of inflexible demand. The calibration of the demand functions is described in detail in Papavasiliou [28]. The resulting economic dispatch model is obtained by enforcing $e_t = 0$ in the economic dispatch model. Again, net demand in the market clearing constraint represents the difference of firm demand and renewable supply.

C. Coupling

In this model an aggregator contractually owns the output from a large group of renewable generation assets. The aggregator enters into a contractual agreement to supply deferrable loads. Loads specify their energy demand in the form of requests for a certain amount of energy over a fixed time window. The aggregator can control the loads directly and uses renewable power from its assets as the primary energy source for satisfying deferrable demand. In the case of renewable supply shortage, the aggregator can resort (to a limited extent) to the real-time market for procuring power at the prevailing real-time price. The aggregator compensates deferrable loads at a rate ρ for each unit of unserved energy. Any excess renewable power is supplied to the system. The setup is similar to dynamic scheduling [29], whereby demand and supply resources from different control areas pair their schedules in order to produce a zero net output to the remaining system. Such scheduling is currently implemented in the ERCOT market. The model is described in detail in Papavasiliou and Oren [30].

IV. Results

A. Preliminaries

We present results for a model of the Western Electricity Coordinating Council (WECC), also used in other studies [31], [15], [16]. The model consists of 124 generators and we do not account for transmission constraints. Details about the system can be found in Papavasiliou et al. [15]. We consider three wind/demand response integration studies that are summarized in Table II. For each level of wind integration, we assume a demand response integration level that is approximately one-for-one in terms of energy demand and capacity. We assume that deferrable requests span over 24 hours. We consider 6 levels of power supply for the control problem. The penalty of unserved energy is $\rho = 5000$ \$/MWh. We use 12 scenarios for the formulation of the stochastic unit commitment model. The wind data that is used for the calibration of the statistical models is based on the National Renewable Energy Laboratory (NREL) 2006 Western Wind and Solar Integration Study [32]. The moderate and deep wind integration studies correspond to the 2012 and 2020 wind integration targets of California. Further details about the wind production data can be found in Papavasiliou and Oren [16]. In order to reduce the computational requirements of the model we focus on eight representative day types instead of simulating an entire year of operations for the system.

B. Validation

In order to verify that the stochastic unit commitment model yields reasonable reserve requirements, the first step in our analysis is to compare its performance against a deterministic benchmark. The results of this comparison are presented in table I. In the table we present summary results for renewable energy waste, operating costs and committed conventional capacity for four case studies under consideration, corresponding to no wind integration, the 33% (deep) integration targets without component outages and the 20% (moderate) and 33% (deep) integration targets with component outages. Renewable energy losses range between 0.2% of total renewable energy production in the case of the deep integration study without transmission constraints and contingencies to 2.5% of total renewable energy production when transmission constraints and contingencies are accounted for. Operating costs decline steeply as the level of renewable power penetration increases, due to the decrease in fuel costs, which are the predominant cost in the system. By comparing the cost of column 2 (Deep-Simple) to that of column 5 (Deep), we note that failing to account for transmission constraints and contingencies results in an underestimation of operating costs by 31.0%. The significant cost increase resulting from transmission constraints can be attributed to the operating cost impacts of contingencies but also to the reduced flexibility of dispatching units in the system.

We note that the moderate integration case reduces average conventional committed capacity by a mere 840 MW, which represents 12.6% of the 6,688 MW of installed wind capacity. Average conventional committed capacity for the deep integration case is reduced by 1,670 MW, which represents 11.8% of

TABLE I
SUMMARY RESULTS FOR EACH CASE STUDY

	Deep-Simple	No Wind	Moderate	Deep
RE waste (MWh)	163	0	877	2,346
Capacity (MW)	19,958	23,619	22,779	21,949
Cost ($M)	5.106	11.283	9.329	7.405
Savings vs Det ($)	145,261	221,854	244,226	207,698
Savings vs SUC2 ($)	39,681	5,022	52,622	15,574

the 14,143 MW of installed wind capacity. Most importantly, we note that failing to account for transmission constraints in the deep integration study results in an underestimation of the committed capacity by 25.9% of installed wind capacity, relative to the estimated 11.8% reduction when these features are accounted for. This strongly supports the argument that the inclusion of transmission constraints and contingencies is crucial for accurately assessing the impact of large-scale renewable energy integration.

The stochastic unit commitment problem of the validation study consist of 42 scenarios and has 909,216 continuous variables, 173,376 binary variables and 2,371,824 constraints. The stochastic unit commitment algorithm was implemented in the Java callable library of CPLEX 12.4, and parallelized using the Message Passing Interface (MPI). The algorithm was implemented on a high performance computing cluster in the Lawrence Livermore National Laboratory on a network of 1,152 nodes, 2.4 GHz, with 8 CPUs per node and 10 GB per node. The parallel implementation of the Lagrangian relaxation algorithm and Monte Carlo simulations is shown in Figure IV-B. $(P1)$ and $(P2_s), s \in S$ were run for 120 iterations. For the last 40 iterations, (ED_s) was run for each $s \in S$ in order to obtain a feasible solution and an upper bound for the stochastic unit commitment problem. The average elapsed time for the 42-scenario problem on twenty machines was 6 hours, 47 minutes. The MIP gap for $(P1)$ and $(P2_s), s \in S$ was set to $\epsilon_1 = 1\%$, and the MIP gap for obtaining a feasible schedule from (ED_s) was set to $\epsilon_2 = 0.1\%$. Note from Table I that the daily savings of SUC-IS relative to SUC2 fall within the MIP gap of the economic dispatch problem for the zero wind integration study. For all other cases (moderate, deep and deep-simple), the benefits of the SUC stochastic unit commitment policy are guaranteed to reflect a superior scenario selection approach. The sum of the optimal solutions of the first and second subproblem yield a lower bound LB on the optimal cost, whereas the optimal solution of the feasibility run results in an upper bound UB. The average gap, $\frac{UB-LB}{LB}$, that we obtained is 0.77%. However, to estimate an upper bound on the optimality gap it is also necessary to account for the MIP gap ϵ_1 that is introduced in the solution of $(P1)$ and $(P2_s), s \in S$. The average upper bound on the optimality gap, $\frac{UB-(1-\epsilon_1)LB}{(1-\epsilon_1)LB}$, is 1.79%.

C. Costs, Load Loss, Capacity Requirements and Spillage

In table III we present the operating costs and daily load losses for the case with no wind and no demand response in the system. The operating costs do not include the cost of lost load. Note that for the average demand of the system

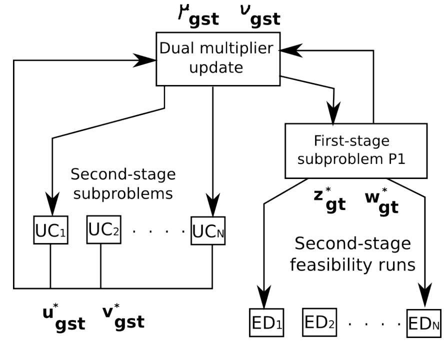

Fig. 2. Parallel implementation of the Lagrangian relaxation algorithm and Monte Carlo simulation.

TABLE II
KEY PARAMETERS OF THE DEMAND RESPONSE CASE STUDY.

	No Wind	Moderate	Deep
Wind capacity (MW)	0	6688	14143
DR Capacity C (MW)	0	5000	10000
Daily wind energy (MWh)	0	46485	95414
Daily DR energy R (MWh)	0	40000	80000
Flexible/firm demand (%)	0	6.1	12.2

under consideration, the 1-day-in-10-years reliability criterion requires daily load shed of no more than 179 MWh. This can be used as a benchmark against which we can compare the extent to which each demand response mechanism is acceptable from a reliability perspective.

In Tables IV, VI we present the daily operating cost of each policy for the moderate and deep integration cases respectively. The column with bold figures, that corresponds to centralized load dispatch by the system operator, contains absolute cost values. Cost figures corresponding to the other policies are relative to the centralized operating costs. The row with total costs weighs the cost of each day type with its relative frequency in the year in order to yield annual results. The last row shows the relative performance of centralized control with respect to the other policies, normalized by the cost of centralized control. Note that the operating costs of price-based demand response outperform those of coupling. This can be attributed to the diversification effect of including flexible demand in the market. The "cost of anarchy" that results from using price signals in order to control load response, rather than centralized control, ranges from 2.43% - 6.88% for the case of demand-side bidding and 3.06% - 8.38% in the case of coupling. Although demand bids result in lower operating costs, demand-side bidding results in load shedding that is 3.4 times greater than the 1-day-in-10-years criterion for the moderate integration case and 6.8 times greater for the deep integration case. Coupling results in the operation of the system within reliability limits as we note in Tables V, VII.

In Table VIII we present a breakdown of operating costs by type for each of the policies that we consider for each integration level. We note that price response and coupling result in cost increases in all cost categories. In Table IX we present the amount of capacity that is committed by each policy as well as the amount of renewable supply spillage.

TABLE III
DAILY COST OF OPERATIONS AND LOAD SHEDDING FOR EACH DAY TYPE FOR THE DEMAND RESPONSE STUDY - NO WIND.

	Daily Cost ($)	Shed (MWh)
WinterWD	7,390,206	0.001
SpringWD	7,145,737	4.317
SummerWD	13,684,880	30.869
FallWD	9,589,506	0
WinterWE	6,079,003	0.001
SpringWE	5,855,883	0
SummerWE	11,839,573	0
FallWE	7,868,146	154.285
Total	9,012,031	17.301

TABLE IV
DAILY COST OF OPERATIONS FOR EACH DAY TYPE FOR THE DEMAND RESPONSE STUDY - MODERATE INTEGRATION.

	Cost ($) Centralized	Δ Cost ($) Coupled	Δ Cost ($) Decoupled
WinterWD	**7,320,620**	256,740	300,051
SpringWD	**6,408,355**	172,006	139,589
SummerWD	**13,625,136**	155,096	219,124
FallWD	**9,640,017**	316,089	157,159
WinterWE	**5,890,755**	300,701	246,408
SpringWE	**3,637,240**	707,223	244,353
SummerWE	**11,739,177**	176,230	234,101
FallWE	**7,735,502**	277,817	189,465
Total	**8,677,857**	265,128	211,010
relative (%)		3.06	2.43

TABLE V
DAILY LOAD LOSS FOR EACH DAY TYPE FOR THE DEMAND RESPONSE STUDY - MODERATE INTEGRATION.

	Shed (MWh) Centralized	Shed (MWh) Coupled	Shed (MWh) Decoupled
WinterWD	0	0	177.257
SpringWD	1.532	1.869	701.828
SummerWD	3.617	4.346	821.719
FallWD	1.661	1.661	799.323
WinterWE	0	0	642.105
SpringWE	0	0.249	453.791
SummerWE	0.059	1.100	215.816
FallWE	6.792	10.005	976.766
Total	1.705	2.217	609.914

TABLE VI
DAILY COST OF OPERATIONS FOR EACH DAY TYPE FOR THE DEMAND RESPONSE STUDY - DEEP INTEGRATION.

	Cost ($) Centralized	Δ Cost ($) Coupled	Δ Cost ($) Decoupled
WinterWD	**6,656,665**	633,164	556,775
SpringWD	**5,692,860**	978,182	572,465
SummerWD	**13,661,862**	505,869	835,609
FallWD	**9,321,281**	772,659	404,523
WinterWE	**5,220,109**	711,882	616,931
SpringWE	**4,251,600**	910,253	576,010
SummerWE	**12,136,223**	329,929	472,930
FallWE	**7,930,823**	700,205	515,431
Total	**8,419,322**	705,497	578,909
relative (%)		8.38	6.88

V. CONCLUSIONS

In this report we present a stochastic unit commitment model that accounts for renewable energy and demand response integration, as well as network component outages. We present a a scenario selection algorithm inspired by importance sampling and a parallel implementation of a Lagrangian relaxation algorithm for solving the model which is shown to outperform a deterministic benchmark. We compare three demand response paradigms: centralized load dispatch, demand-side bidding and coupling. We analyze the case of no wind in the network, as well as cases of wind integration that correspond to the 2012 and 2020 wind integration targets of California, with a corresponding one-for-one increase in flexible demand. Our analysis is performed on a model of the Western Electricity Coordinating Council that consists of 124 generators.

TABLE VII
DAILY LOAD LOSS FOR EACH DAY TYPE FOR THE DEMAND RESPONSE STUDY - DEEP INTEGRATION.

	Shed (MWh) Centralized	Shed (MWh) Coupled	Shed (MWh) Decoupled
WinterWD	0.001	8.290	552.769
SpringWD	0	351.782	1382.459
SummerWD	0.001	36.643	1952.332
FallWD	33.660	143.629	1210.443
WinterWE	0	0	929.960
SpringWE	0	32.601	1008.222
SummerWE	2.081	58.725	1157.565
FallWE	57.005	132.134	1260.137
Total	10.231	112.452	1221.492

TABLE VIII
BREAKDOWN OF DAILY OPERATING COSTS FOR EACH DEMAND RESPONSE POLICY FOR EACH INTEGRATION LEVEL ($).

	Min load	Fuel	Startup	Total
No wind	1,382,156	7,549,491	80,384	9,098,537
Centralized Moderate	1,246,552	7,364,815	66,489	8,677,857
Bids Moderate	1,317,383	7,471,363	100,123	8,888,866
Coupled Moderate	1,330,130	7,532,898	79,958	8,942,958
Centralized Deep	1,194,606	7,174,611	50,105	8,419,322
Bids Deep	1,360,543	7,494,472	143,217	8,998,232
Coupled Deep	1,432,948	7,592,595	99,276	9,124,819

TABLE IX
CAPACITY REQUIREMENTS AND WIND POWER SPILLAGE FOR EACH DEMAND RESPONSE POLICY.

	Capacity (MW)	Spillage (MWh)
No wind	26,123	N/A
Moderate	26,254	0
Deep	26,789	2

VI. PERSPECTIVES

There are various extensions that are intended in future research. In practice, system forecasts can and will be updated, leading to the opportunity for individual units to be committed or de-committed as required. The fact that forecasts and dispatch decisions are revised during the day can be represented through a multistage formulation of the stochastic unit commitment problem. The model can also be extended to an optimal investment model, where the first stage is interpreted as investment in new generation capacity. The inclusion of investment decisions on transmission lines in order to integrate increased amounts of renewable resources also represents an exciting area of future research. In addition, we are interested in exploring a more detailed model of demand response based on a notion of the 'value of storage', analogous to the notion of the 'value of water' in medium-term hydrothermal planning models, that can be integrated in the stochastic unit commitment model without requiring a discretization of the state space of deferrable demand.

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Mitigating Renewables Intermittency Through Non-Disruptive Distributed Load Control (3.2)

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***Abstract*—This research project explores the coordination of aggregations of thermostatically controlled loads (TCLs; including air conditioners and refrigerators) to manage frequency and energy imbalances in power systems. We focus on central control of loads and examine (1) strategies to control loads with limited communications and control infrastructure, (2) the potential to arbitrage variations in wholesale electricity prices by shifting demand over short time scales and (3) an understanding of the economic potential for various residential loads to provide power system services. Our results indicate that: (1) power tracking RMS errors in the range of 0.26–9.3% of steady state aggregated power consumption are possible, and this can be achieved without TCLs providing state information to a central controller in real time, (2) TCLs could save on the order of 10% of wholesale energy costs via arbitrage and (3) for several residential load types, fast demand response applications could be cost effective and profitable.**

I. Introduction

Electric loads can improve electric grid reliability and reduce wholesale electricity prices by participating in direct load control and demand response (DR) programs to [1], [2]. Traditional research in this area has focused on developing strategies that enable loads to *decrease* power use in the event of loss of generation or high prices, e.g., [3], [4], [5]. Recent research has explored incorporating local load states into control decisions to enable nondisruptive load reductions [6], [7]. This paper also focuses on nondisruptive[1] control, but for the purpose of delivering services such as load following and regulation by both decreasing and *increasing* power use over short time scales. The need for these services is likely to grow with increasing production from wind and solar generators, which are expected to increase frequency deviations and energy imbalance [8]. Thermostatically controlled loads (TCLs), such as refrigerators, air conditioners, and electric water heaters, are excellent candidates for providing these services because they are capable of storing thermal energy, much like a battery stores chemical energy [9]. TCLs may have advantages relative to other options (such as battery storage) because the amount of balancing capacity they can potentially deliver far exceeds that available from wind generators and expected amounts of storage in the near term.

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[1]In this context, non-disruptivity implies that the temperature of any controlled TCL does not leave its original range.

This research project has three central objectives. The first is to gain insight into the level of sensing and communications infrastructure that is required to enable fast DR. The studies referenced above assume that power measurements are available from all loads for real-time feedback control. This paper relaxes that assumption since it is currently expensive to integrate real time power measurement telemetry for ancillary services into existing utility SCADA systems: Pacific Gas and Electric Company spent more than $140,000 per load in a 2009 study [10] and Southern California Edison recently estimated costs to be about $70,000 per measurement point [11]. We also focus on centralized control to preserve visibility and controllability in the control room. Specifically, we examine the effect of limited sensing and communications on the accuracy of centrally-controlled aggregations of TCLs participating in 5-minute energy markets (i.e. load following).

The second objective is to use concepts from the control framework in the first objective to quantify potential energy cost savings associated with shifting load in response to real time wholesale prices. We develop an optimal control formulation that accounts for the specific capabilities and constraints of TCL aggregations, especially the time-varying nature of the resource and preserves non-disruptivity.

Our third research objective is to quantify the economic case and potential impacts of the aggregated residential TCL resource in California, again by limiting the control options to those that are non-disruptive. We focus on refrigerators, air conditioners, heat pumps and water heaters. To achieve this we use models of TCL populations from the first objective to estimate the size of the TCL resource (in GW and GWh), possible financial rewards, and costs associated with deploying enabling infrastructure.

II. Approach-Methods

Figure 1 shows the information hierarchy we consider in this research. The local level consists of controllable TCLs that may be metered to transmit information to a central controller (the global level). The semi-global level consists of distribution substations, where one can measure the power consumed on feeders and estimate the state of controlled TCLs. We will assume all decisions originate at the global level (whether by a system operator or load aggregator responding to system operator commands), and explore several different scenarios of information available at the global level from various levels in the hierarchy.

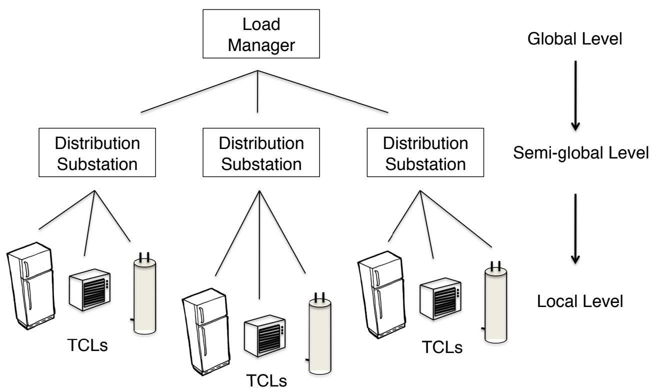

Fig. 1. Electric power system information hierarchy.

A. Model 1: Aggregation of Individual TCL Models

Model 1 is a high fidelity model used as the plant within each framework. A direct way to model an aggregation of heterogenous TCLs is to simulate thousands of individual TCLs using the first-order model developed in [12], [13], [14]. In this model, each TCL's temperature state evolution is described with a stochastic hybrid difference equation:

$$\theta^i_{k+1} = a^i\theta^i_k + (1-a^i)(\theta^i_{\mathrm{a},k} - q^i_k\theta^i_{\mathrm{g}}) + \epsilon^i_k, \tag{1}$$

where θ^i_k is the internal temperature of TCL i at time step k, θ_{a} is the ambient temperature, and ϵ is a noise process. The dimensionless TCL parameter a^i is defined as $e^{-h/(C^iR^i)}$, where C^i is a TCL's thermal capacitance, R^i is its thermal resistance, and h is the model time step. θ^i_{g} is the temperature gain when a TCL is on and is equal to $R^iP^i_{\mathrm{trans}}$, where P^i_{trans} is a TCL's energy transfer rate, which according to our conventions is positive for cooling TCLs and negative for heating TCLs. P^i is defined as the power consumed by TCL i when it is on, and is equal to $|P^i_{\mathrm{trans}}|/\mathrm{COP}^i$, where COP^i is its coefficient of performance. The local control variable q^i is a dimensionless discrete variable equal to 1 when the TCL is on and 0 when the TCL is off. For cooling TCLs, it evolves as follows:

$$q^i_{k+1} = \begin{cases} 0, & \theta^i_{k+1} < \theta^i_{\mathrm{set}} - \delta^i/2 \\ 1, & \theta^i_{k+1} > \theta^i_{\mathrm{set}} + \delta^i/2 \\ q^i_k, & \text{otherwise} \end{cases} \tag{2}$$

where θ^i_{set} is the set point and δ^i is the dead-band width. For heating TCLs, the position of the 0 and 1 are switched.

We assume that a centralized direct load controller can switch loads on or off while the loads are within their temperature dead-band; however, it can not change a TCL's temperature directly or affect its set point. Additionally, to guarantee local comfort, we assume TCLs become unavailable to a central controller if outside of the dead-band.

TCLs with compressors (air conditioners and refrigerators) should not be cycled on/off too quickly or else the compressor may fail. While this constraint is not explicitly included in the individual TCL model, the external controller can be designed to minimize the chance of compressor short-cycling, for example, by preferentially switching TCLs that are about to switch and/or not allowing TCLs in certain states to switch.

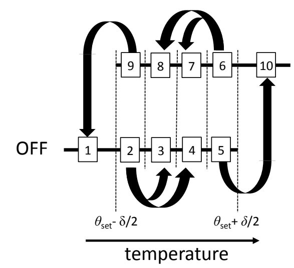

Fig. 2. Discretized dead-band used in the extended state bin transition model ($n = 10$) for cooling TCLs. Not all possible transitions are shown.

B. Model 2: Extended State Bin Transition Model

Figure 2 shows a discretized dead-band for an aggregation of loads. The discrete time motion of TCLs around the discretized state space can be described by a Markov transition matrix, the transpose of which is the A-matrix commonly used in control applications.

$$x_{k+1} = A_kx_k + Bu_k \tag{3}$$
$$y_k = C_kx_k, \tag{4}$$

where the vector x represents the fraction of loads in each temperature bin depicted in Figure 2 and each element of A_k describes the rate of movement of TCLs from one bin to another. The model can be time variant (meaning A_k would change with k) or not, depending on the application.

We assume that we can control TCLs within the dead-band by turning them on or off. Thus, we define an input $u \in \mathbb{R}^m$. The absolute value of each entry of u is the fraction of the total TCLs in a temperature interval to be turned on/off. Negative values of u turn TCLs off, while positive values turn TCLs on. Corresponding to the bin numbering in Figure 2, $B \in \mathbb{R}^{n\times m}$ is as follows:

$$B = \begin{bmatrix} 0_{1\times m} \\ -I_{m\times m} \\ J_{m\times m} \\ 0_{1\times m} \end{bmatrix},$$

where J is an anti-diagonal matrix with ones on the anti-diagonal. The choice of B ensures that we do not control TCLs in the outside bins, and that TCLs that switch from an on bin end up in the corresponding off bin and vice versa. The output measurement y can take several different forms and we discuss these in Section II-D.

To minimize communication from the central controller to the TCLs, we divide the entries of u by the relevant entries of x to create a control vector of "switch probabilities" u_{rel}, which we broadcast to all TCLs. TCLs decide whether or not to switch probabilistically, by comparing a random number drawn from a uniform distribution between 0 and 1 to the entry of u_{rel} corresponding to their current state. Note that if we have a poor estimate of x our control may be poor [15].

Discussion of the details of identifying the parameters of this model can be found in [15], [16]

C. Model 3: Time-varying Thermal Battery Model

Model 3 is used to compute near-optimal control trajectories. Because it has low dimensionality, the model simplifies

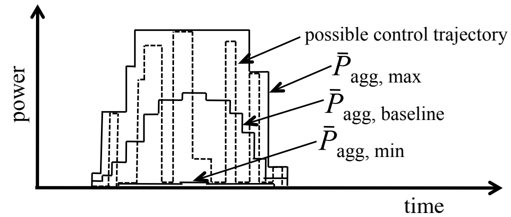

Fig. 3. A TCL population's baseline and power constraints. The TCL population also has energy constraints, not shown.

real time optimization but is not useful for control because it inaccurately represents system dynamics. Instead it keeps track of a TCL population's energy state, S_j, as a function of its mean aggregate power usage, $\bar{P}_{\text{agg}}$, in each price interval, j, of width ΔT. Without external control, a TCL population's time-varying power trajectory is referred to as its "baseline." Figure 3 shows a TCL population's mean aggregate power baseline, $\bar{P}_{\text{agg, baseline}}$, over a day. A TCL population increases it energy state when $\bar{P}_{\text{agg},j} > \bar{P}_{\text{agg, baseline},j}$, and decreases it when $\bar{P}_{\text{agg},j} < \bar{P}_{\text{agg, baseline},j}$:

$$S_{j+1} = S_j + (\bar{P}_{\text{agg},j} - \bar{P}_{\text{agg, baseline},j})\Delta T. \tag{5}$$

As shown in Fig. 3, the choice of $\bar{P}_{\text{agg},j}$ is constrained:

$$\bar{P}_{\text{agg, min},j} \leqslant \bar{P}_{\text{agg},j} \leqslant \bar{P}_{\text{agg, max},j}. \tag{6}$$

S is also constrained:

$$0 \leqslant S_j \leqslant S_{\text{max},j}. \tag{7}$$

These bounds define the *power and energy capacity* of a TCL population. When $S = 0$ the thermal battery is depleted meaning all TCLs operate at one edge of the dead-band (e.g., for cooling TCLs all operate near $\theta_{\text{set}} + \delta/2$). When $S = S_{\text{max}}$, the thermal battery is full meaning all TCLs operate at the other edge of the dead-band.

Parameter derivations are available in [16].

D. Centralized Control of the TCL Population

If the only real time measurement is TCL aggregate power, $P_{\text{total,meas}}$, y is a scalar and $\boldsymbol{C}$ is a row vector as follows:

$$\boldsymbol{C} = \underbrace{\bar{P}_{\text{ON}}\, N_{\text{TCL}}}_{c_p} [\underbrace{0, \cdots, 0}_{\frac{N_{\text{bin}}}{2}}, \underbrace{1, \cdots, 1}_{\frac{N_{\text{bin}}}{2}}] \tag{8}$$

where N_{TCL} is the number of TCLs in the population and $\bar{P}_{\text{ON}}$ is the mean power consumption of TCLs in the ON state. Note that $\bar{P}_{\text{ON}}$ may not equal the mean power of all TCLs in the population since TCLs with lower rated power may spend proportionally more time in the ON state. $\bar{P}_{\text{ON}}$ can be computed if all TCL parameters, ambient temperatures, and dead-bands are known, or if ON/OFF state information is available and the aggregate steady state power consumption of the population, $P_{\text{total,ss}}$, is known.

For the reference case, described in Section III-A, we assume full state information from all TCLs is available in real time. In that case, $\boldsymbol{C}$ becomes an $(N_{\text{bin}}+1) \times N_{\text{bin}}$ matrix:

$$\boldsymbol{C}_{\text{ref}} = \begin{bmatrix} \boldsymbol{I}_{N_{\text{bin}} \times N_{\text{bin}}} \\ \boldsymbol{C} \end{bmatrix}. \tag{9}$$

Though not considered here, one could use $\boldsymbol{C}_{\text{ref}}$ if full state information is available in real time from a subset of TCLs.

The pair $[\boldsymbol{A}, \boldsymbol{B}]$ is not controllable: the controllability matrix is of rank $n-1$ because the controller cannot drive all states to zero (the fraction of TCLs in each bin must sum to one). However, for both $\boldsymbol{C}$ and $\boldsymbol{C}_{\text{ref}}$, aggregate power can be tracked and the system is observable.

We developed two lookahead controllers. Each entails first computing the total fraction of TCLs to switch either ON or OFF in the next time step, u_{goal}, defined as follows:

$$u_{\text{goal,k}} = K \frac{P_{\text{total,des,k+1}} - \bar{P}_{\text{total,pred,k+1}}}{N_{\text{TCL}} \bar{P}_{\text{ON}}} \tag{10}$$

where K is the control gain and $P_{\text{total,pred}}$ is the predicted aggregate power. If the state estimates are near perfect, then the aggregate power estimate is near perfect and K should be one. However, if there is significant error in the state estimates, $K = 1$ can result in high frequency oscillations. Therefore, for Scenario 1 and Scenario 2 (100% metering), we set $K = 1$, and for the other cases we selected K through iterative tuning to minimize RMS error.

The two controllers differ in how u_{goal} is divided amongst the bins. We assume that control actions can not force TCLs that are outside of the dead-band to switch. Since bins 1 and $\frac{N_{\text{bin}}}{2} + 1$ may contain TCLs that are outside of the dead-band, we do not apply control to these bins in systems with $N_{\text{bin}} > 2$. In systems with $N_{\text{bin}} = 2$, control actions are applied to TCLs regardless of their temperature state, generally resulting in too few TCLs switched.

Controller 1 divides u_{goal} equally amongst all of the allowable OFF or ON bins depending upon the sign of u_{goal}. Since the division of u_{goal} does not take into account the number of TCLs in each bin, a bin may be called on to switch more TCLs than are actually in that bin, resulting in a 100% switch probability and too few TCLs switched.

Controller 2 preferentially switches TCLs in bins closer to the edge of the dead-band, with the goal of switching TCLs that are about to 'naturally' switch, therefore minimizing the total number of times a single TCL is switched over time. Additionally, if vapor compression equipment operates for very short time intervals (less than a few minutes), it is possible that lubricant will become trapped in the refrigerant lines outside of the compressor. This may lead to premature failure of the compressor. Controller 2 is designed to avoid compressor short cycling. The controller uses the current state estimates to assign fractions of TCLs to switch sequentially to the bin closest to the dead-band, the following bin, and so on, until all of u_{goal} has been assigned. Error in state estimates results in either too few or too many TCLs switched.

E. Optimal Control Framework: Decoupled Optimization and Control

We aim to determine the optimal mean aggregate power consumption in each interval, $\bar{P}^*_{\text{agg}}$, and so we solve:

$$\min \Delta T \sum_{j=t}^{t+N} L_j \bar{P}_{\text{agg},j} \tag{11}$$
$$\text{s.t. } (5), (6), \text{ and } (7),$$

TABLE I
SCENARIOS.

	System Identification	Information Available in Real Time	State Estimation	Minimum Infrastructure Required
Scenario 1	Offline, using TCL parameters or $\boldsymbol{x}_{\text{meas}}$ and $P_{\text{total,ss}}$	Temperature and power consumption from all TCLs, measured perfectly	Full state measured; Kalman Filter	TCL-level low-latency two-way data connection, TCL temperature sensor, TCL power measurement/knowledge, local decision making*
Scenario 2	Same as Scenario 1	ON/OFF state information from 100% or 30% of TCLs	Full state not measured; Kalman Filter	TCL-level low-latency two-way data connection, TCL ON/OFF state measurement/knowledge, local decision making*
Scenario 3	Same as Scenario 1	Distribution area power consumption and forecasts, assuming forecast error standard deviations of 5% or 10% of the the substation load	Same as Scenario 2	TCL-level low-latency one-way data connection, substation-level low-latency one-way data connection, substation power measurement, local decision making*
Scenario 4	In real time, using an EKF to identify the $\boldsymbol{A}$-matrix; assumes knowledge of c_p	Same as Scenario 3	EKF	Same as Scenario 3

*Local decision making capabilities are required to translate the control input vector into actions.

where L_j represents the real-time cost of electricity. This problem can be solved as a receding-horizon LP. We then transform $\bar{P}^*_{\text{agg}}$ into a control trajectory p^*_{agg} with the correct time step; specifically, $p^*_{\text{agg},k} = \bar{P}^*_{\text{agg},j}$ for $k = t, t+h, ..., t+\Delta T - h$.

Model 2 is used to track p^*_{agg} with the predictive proportional controller (PPC) proposed in [15]. Our goal is to calculate u_{goal}, the total fraction of TCLs to switch on or off in the next time step. First, we compute:

$$u'_{\text{goal},k} = \frac{p^*_{\text{agg},k+1} - y_{k+1}}{N_p \bar{P}_{\text{ON},k}}, \tag{12}$$

where y_{k+1} is computed with (3) and (4). Then, $u_{\text{goal},k}$ is calculated by putting $u'_{\text{goal},k}$ through a saturation filter with minimum equal to the fraction of TCLs on, $-\sum_{s=m+2}^{n} x_{s,k}$, and maximum equal to the fraction of TCLs off, $\sum_{s=1}^{m+1} x_{s,k}$. u_{goal} can be distributed to the bins in different ways, for example, equally or by preferentially switching TCLs that are about to switch. Here we do the latter. This avoids compressor short-cycling; however, when the system attempts to minimize energy consumption this could still occur.

III. Results

In this section we will give an overview of project results. For more details please refer to [15], [16], [18].

A. Analysis of Infrastructure and Communications Scenarios (Centralized Controller)

We considered four scenarios for communications infrastructure to test the performance of the centralized control approach. See Table I for description of the scenarios.

$P_{\text{total,des}}$ was designed to mimic California Independent System Operator (CAISO) 5-minute market signals, described in [19]. (See [15] for more discussion.) To evaluate tracking performance, we used two metrics: (1) the RMS power tracking error as a percentage of the steady state power consumption of the population and (2) the Compliance Threshold (CT). The CT is relevant to the CAISO, which defines non-compliance as deviation from desired power values by a specific threshold for more than n_{nc} consecutive intervals [19]. After a period of non-compliance, a resource can become compliant by coming within the threshold for n_{c} of consecutive intervals [19]. We define the CT as the minimum power value at which the TCL population is compliant, and set $n_{\text{nc}} = 3$ and $n_{\text{c}} = 1$, which are the values the CAISO initially uses for a new resource.

TABLE II
MODEL / ESTIMATOR / CENTRALIZED CONTROLLER RESULTS

Case	$N_{\text{bin}} = 2$*		$N_{\text{bin}} = 40$			
	Controller 1/2		Controller 1		Controller 2	
	RMS (%)	CT (kW)	RMS (%)	CT (kW)	RMS (%)	CT (kW)
Scenario 1, Reference Case	0.91	15	0.59	20	0.57	7
Scenario 2, 100% metering	0.95	20	0.69	8	0.76	21
Scenario 3, 5% Forecast Error	7.6	156	5.2	72	6.3	180
Scenario 4, 5% Forecast Error	7.1	59				

*For $N_{\text{bin}} = 2$, both controllers produce the same control input, so we only report one set of results.

We present a subset of our results, for 1,000 simulated TCLs in each run, in Table II. For more scenarios (different numbers of bins, different forecast errors, different numbers of simulated TCLs), please see [15].

Generally, as less information is available for system identification, state estimation, and control, the tracking performance degrades. An exception is Scenario 4 in which the TCLs perform better than the TCLs in Scenario 3, 2 bins. This indicates that there is some value in the $\boldsymbol{A}$-matrix not being fixed. We found that systems with more bins almost always produce better tracking results (result not shown). Systems with more bins more accurately predict aggregate power in the next time step, provided the TCL population model and state estimates are accurate.

The results also show that Controller 2 performs worse than Controller 1. This is because Controller 2 is more sensitive to bad state estimates and forces the system further from steady state by preferentially switching devices in bins closer to the dead-band. The benefit, however, to Controller 2 is that the resulting off-times are nearly the same as an uncontrolled system, whereas for Controller 1 the off-times can be quite short (and this matters for short cycling).

The CTs do not vary as systematically as the RMS error results because the values are computed with only 12 data points – the aggregate power at the halfway point of each 5-minute interval. There is no existing performance metric used to determine if a resource is ramping linearly. Since TCLs may not ramp linearly it would be worthwhile to develop such a metric.

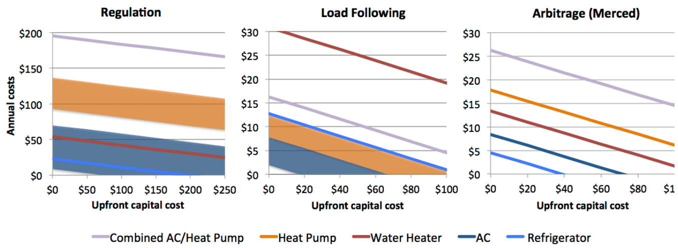

Fig. 4. Per-TCL capital and annual costs required to break even.

B. Optimal Control for Load Following

In this section we present a subset of our results from [16] relating to optimal control of loads for energy arbitrage. We used CAISO 5 minute locational marginal prices for a trading hub near Merced, CA, in combination with coincident Merced weather files to drive cooling loads. When we control the population to track the optimal trajectory, we find maximum savings are approximately 14%. This translates to about $13 in wholesale energy cost savings per TCL per year. Since this analysis assumes perfect price and weather forecasts and exogenous electricity prices, this is an upper bound on the potential energy costs savings in Merced. An aggregator would need to decide if arbitrage revenues could be sufficient to cover upfront costs including hardware, software, and installation; reoccurring costs including operations, maintenance, and incentive payments to customers; and its desired profit margin.

C. Demand Response Resource Potential

This section presents a subset of our results concerning the economic potential for fast demand response to provide power system services. More detailed results are available in [18],.

Here we will present break-even cost points for DR by comparing regulation, load following, and arbitrage revenues to potential ranges of upfront capital costs and annual costs. Upfront costs include the cost of necessary equipment to enable control, as well as hardware/software installation costs. Annual costs include reoccurring maintenance and compensation to customers participating in the programs.

We calculated the annualized capital cost using a lifetime of 20 years and a real discount rate of 10% over a range of installed costs from $0 to $250. Then we calculated the maximum annual cost per TCL that would make total annual costs equal to the potential annual revenue. Results are presented in Figure 4. If the total installation and annual participant costs required to enable a TCL to participate in regulation, load following, or arbitrage fall below and to the left of the lines in Figure 4, then TCLs can potentially make money in these markets. For ACs and heat pumps providing regulation and load following, we present ranges bounded by values computed with the mean per-TCL earning potential from California Energy Commission (CEC) Zone 10 (LA Basin Inland) and CEC Zone 5 (San Francisco). For combined ACs/heat pumps providing regulation and load following, we present values for CEC Zone 6 (Sacramento) since all zones had similar results. For arbitrage, we use values from the Merced analysis. Battery technologies in a recent study (EPRI 2010) have much higher installed costs.

Figure 4 shows that a wide range of cost structures for DR-enabling technologies would allow TCLs to participate profitably in regulation, load following, or energy arbitrage. Refrigerators and water heaters are well-suited to the hour-scale requirements of providing load following, given their large energy storage capacities relative to their power capacities, while air conditioners and heat pumps are better-suited to the shorter-timescale regulation market. While the cost structures for enabling technologies and customer compensation are uncertain, the range of profitable cost structures indicates that fast DR could be cost-effective and profitable.

IV. Conclusions

This research has shown it is possible to control loads with very little communications infrastructure, though tracking performance generally degrades as less information is available. These findings provide encouraging evidence that, depending on engineering and policy objectives, the cost to instrument demand side portion of the "smart grid" may quite low. Indeed the required communications infrastructure may be no more substantial than a simple broadcast receiver at each load plus a low power transmitter and conventional SCADA system in each distribution substation. The appeal of this approach is that it can be implemented directly on top of existing distribution companies' efforts to modernize their networks, with little additional investment in infrastructure.

We also found that a population of air conditioners participating in energy arbitrage in CAISO's 5-minute energy market in Merced could save, at most, 14% of wholesale energy costs, which translates to about $13 per TCL per year. In locations where air conditioners are more heavily used and/or intra-day electricity market prices are more volatile (e.g., future electricity markets with more intermittent renewable resources), the potential savings would be higher. Ultimately though, the ability of a load aggregator to profit from arbitrage is a function of its ability to forecast prices and temperatures and the effect of its actions on the market prices. As we showed in [16], stochasticity reduces energy cost savings potentials, making realistic energy cost savings seem rather modest. A load aggregator would need to determine if expected revenues would provide sufficient profit after covering the costs associated with TCL control, e.g., hardware, software, operations & maintenance, and compensation to the TCL owners.

Finally, we found that existing TCLs could provide a substantial portion of the fast timescale reserves required in power systems with high penetrations of intermittent renewables, and that the approach has the potential to be profitable. Specific results depend upon the type of TCL and, for ACs and heat pumps, the climate that the TCL operates in.

V. Future work

There is a need for other methods for estimation and the use of more intelligent controllers. In this research we analyzed systems without communications delays or bandwidth constraints. Concepts from networked control systems and model predictive control (MPC) may be useful for further investigating these scenarios and assigning control actions for periods when communication is not possible. An MPC framework could also help minimize excessive TCL switching and keep the TCL population closer to steady state.

We also believe there is a need for refined models [20] and the design of a receding horizon controller that takes into account stochasticity. Additionally, it could consider the effects of user behavior on energy cost savings and ways to explicitly account for the effect of real-world constraints, such as compressor lock-out (which helps TCLs avoid short-cycling), on TCL population's energy/power capacities.

As more TCLs participate in power system services, the marginal value of avoided procurement of ancillary services will likely decrease, and the revenues of TCL populations along with it. This downward force on value could be countered, perhaps strongly, by increased production variability from renewable sources. Further research is required to characterize the shape of ancillary service cost curves and thus the magnitude of TCL revenue reduction.

VI. Acknowledgement

We thank Taylor Keep, Froy Sifuentes, Dave Auslander and Hosam Fathy for stimulating conversations and feedback.

VII. Project publications and access to products

Please see [15], [16], [18] for project publications. They are accessible on IEEE Xplore and on the ACEEE website.

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VIII. Biographies

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Planning and Market Design for Using Deferrable Demand to Meet Renewable Portfolio Standards and Emissions Reduction Targets (3.3)

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***Abstract*--The primary objective of this Task is to develop an *integrated multi-scale physical and economic* framework to determine the system and environmental benefits of Deferrable Demand (DD). In this framework, aggregates of Plug-in Electric Vehicles (PEV) and of thermal storage at different nodes are managed optimally using a stochastic form of Multi-period Security Constrained Optimal Power Flow (MSCOPF). The MSCOPF also includes cost/damage coefficients for emissions at different nodes as well as the fuel and ramping costs for generating units. Results show that DD and an equivalent amount of storage capacity collocated at wind sites both reduce operating costs by dispatching more wind generation, reducing ramping needs and smoothing the dispatch of conventional generating units. The added advantages of DD are 1) it reduces congestion on the network, 2) its capital cost is shared with another energy service (transportation or space cooling), and 3) lower bills for customers.**

I. Introduction

We have developed an *integrated multi-scale physical and economic* framework to evaluate the potential benefits of Deferrable Demand (DD) as a relatively inexpensive form of storage that can be used to mitigate the inherent variability of renewables sources of generation and reduce system costs. The basic structure of this framework is to construct models of the aggregate loads of individual customers who own Plug-in Electric Vehicles (PEV) and of commercial customers with thermal (ice) storage for space cooling. These models provide realistic constraints on the charging/discharging capabilities at a node that are used as inputs into a stochastic form of MSCOPF (the second generation SuperOPF). Other inputs include the stochastic characteristics of wind generation at different nodes on a network. The SuperOPF minimizes the expected cost of meeting load over a 24-hour horizon. The components of the integrated framework are illustrated in Figure 1.

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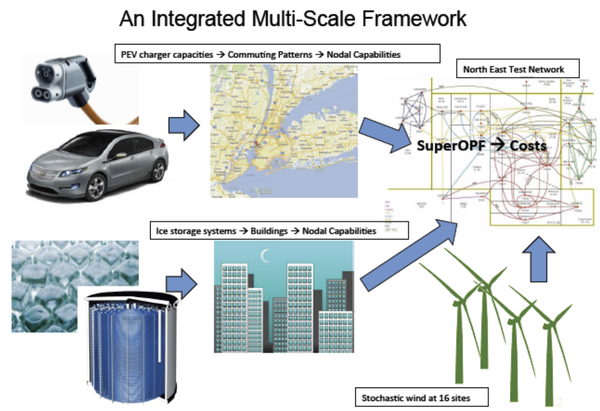

Fig. 1. The structure of the integrated multi-scale framework

The next section has three parts that describe the models for 1) PEVs, 2) thermal storage, and 3) the SuperOPF. Section III presents an empirical application of the integrated framework for a test network with stochastic wind inputs at 16 sites. The results compare the system effects of DD at 5 load centers with an equivalent amount of utility-scale storage collocated at the wind sites. Both types of storage reduce the system costs by 1) dispatching more wind, 2) providing ramping services, and 3) reducing the amount of conventional generating capacity needed to maintain reliability. The main difference in the total cost is that some of the capital cost of DD is shared with the provision of another energy service (transportation or space cooling).

II. Approach/Methods

A. Transportation Systems Modeling

1) Transportation Network Modeling

The objective of transportation systems modeling is to develop an upper bound on the feasible amount of charging by PEV owners each hour aggregated to the nodal level. The first step is to estimate the temporal and spatial profiles of commuters arriving at and leaving homes using a data-driven transportation network model for the Northeast based on the U.S. Department of Transportation's 2000 Census Transportation Planning Package (CTPP) and the Regional Travel Household Interview Survey (RTHIS) [1]. We first focus on the New York Metropolitan Area (NYMA) and then apply the method to the rest of the Northeast. For example, The Journey-to-Work data in the CTPP is used to determine the number of commuters that drive daily to New York City from every county in the NYMA. RTHIS itemizes the time when a random NYMA commuter leaves work for home. By assigning a different Travel Time Index (TTI) corresponding to "center city", "suburban", and "rural" areas in the region, we conducted Monte Carlo simulations of a thousand commuters to create a normalized commuter-at-home profile (CHP) [1]. The simulation provides a realistic sample of a variety of commuter transportation patterns that include different PEV battery recharge requirements, and home arrival and departure times.

B. Charging Infrastructure

As 85% of commuters in the U.S. drive 40 miles or less every day, the charging need for a typical PEV-40 (40-mile electric range) ranges from 10 kWh for a compact sedan to 18.4 kWh for a full-size sports utility vehicle. There are two types of electric vehicle chargers considered in this study: Level 1 chargers are standard 120 V/12 A outlets, capable of delivering a maximum of 1.44 kW, while Level 2 chargers are rated at 240 V/32 A and can deliver 7.68 kW. Level 2 chargers with higher power ratings are not analyzed as it may cause current batteries and distribution transformers to overheat during vehicle charging. Furthermore, PEVs will most likely be charged at owner's homes, at least in the short-term.

1) Charge Flexibility Constraint

Using the transportation system model and assuming a mixture of charge capacities, we derived a Charge Flexibility Constraint (CFC), which limits the amount of aggregate power withdrawn for PEV charging [2]. Varying temporally, the CFC is constructed from the probability of CHP, PEV battery requirements, and the mixture of Level 1 and Level 2 chargers (Fig. 2). If charging takes place at other locations, such as at work, then a less restrictive CFC profile describing vehicle idleness would be used instead.

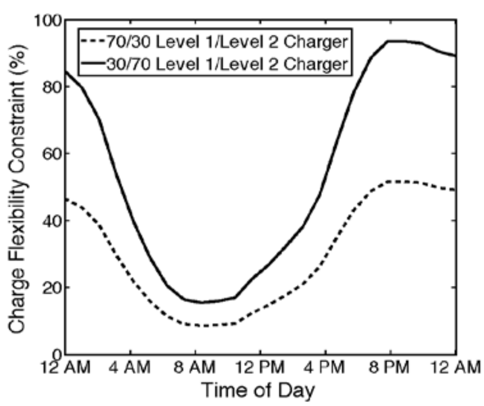

Fig. 2. Charge Flexibility Constraint (CFC) with 70/30 and 30/70 (Level 1/Level 2) charging infrastructure

2) Charging Mechanisms

Charging-at-will refers to charging the PEVs as soon as the commuter arrives home, and finishing when the battery becomes full or when the commuter leaves home. This type of charging scheme tends to exacerbate the peak load and the Locational Marginal Price (LMP) of electricity.

Valley-filling charging is an approach that intuitively allocates all of PEVs' required charge at valley-load hours. This approach only charges PEVs when the system load and LMP are low at night. The standard valley-fill approach allocates PEV charging make the valley have a flat load. There are several variations to this basic approach, including smoothing to reduce generator ramping. This charging constraint places severe limitations on any valley-filling approach when the valley-load is centered on 5 AM. However, due to a sharp decrease in the CFC from 1 AM to 6 AM, a valley-load shift to 1–3 hours earlier significantly diminishes the effect of the CFC [1].

Intelligent Charging allows an aggregator to allocate PEV charging to minimize the system energy and ramping costs in the day-ahead and real-time wholesale markets [1]. This charging can occur at any time when commuters are at home, and it is, therefore, not limited to valley-load hours. In an empirical application to test the model, the savings in system costs with intelligent charging were 6-15% compared to charging-at-will.

C. Building Systems Modeling

The objectives of building systems modeling are to 1) estimate the maximum potential for installing ice storage systems (ISS) in buildings, and 2) evaluate the efficiency of ISS and provide parameters for evaluating the effects of ISS on system costs.

1) Maximum Potential for Installing ISS

The analysis considers the cooling loads for large-commercial and industrial buildings because we expect the penetration of ISS will be highest in these sectors. Once again, the initial focus is on New York State (NYS), and the same method will be applied to the rest of the Northeast. First, we derive the spatial and temporal profiles of the total electricity consumption by the building sector based a number of sources [2]. Data from the New York State Energy Research and Development Authority (NYSERDA) was used to determine the breakdown of customers. The number and types of buildings for NYS was determined using information from the U.S. Census and the Energy Information Administration (EIA). The end-use electricity consumption by building type was obtained from the Residential Energy Consumption Survey (RECS), Commercial Buildings Energy Consumption Survey (CBECS), and Manufacturing Energy Consumption Survey (MECS).

Fig. 3 shows the load profiles from the large commercial and industrial buildings in New York State [2]. Total Load is divided into Fixed Load, that cannot be shifted through time and includes non-cooling load and critical cooling load, and MaxFlexHVACLoad that represents the potential DD associated with ISS. In other words, MaxFlexHVACLoad is the maximum potential for installing ISS.

1) Ice Storage System Modeling

To characterize ice storage systems in buildings, we conducted detailed building simulations using TRNSYS, a dynamic simulation software package. Fig. 4 depicts a representative ISS for large commercial buildings. The ISS consists of two separate loops: a glycol mixture loop for ice making and a water loop that provides continuous cooling load to the building [3]. Each of these loops uses a pump in to provide the desired flow rates for the system, and a fan is used to deliver the cooling load. The system operates in two different modes, ice-making/charging, and ice-thawing/discharging. The ice-making mode consists of both the glycol and the water loop running independently of each other. The glycol loop transfers cooling load from the ice chiller to the ice storage tank to make ice, and the water loop provides direct cooling to the building. This mode is used exclusively during times when the base load chiller can provide all of the cooling needs of the building, which, given cooling demand patterns, happens only during the night and early morning.

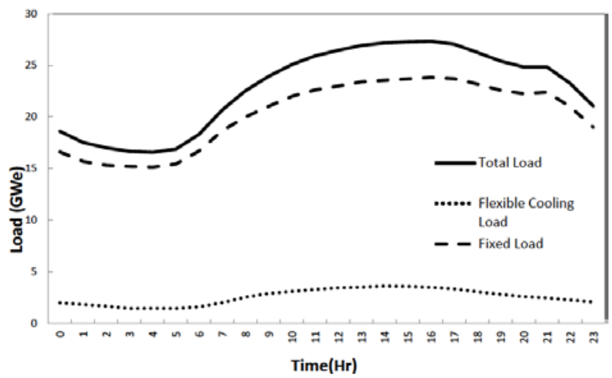

Fig. 3. Load profiles of large commercial and industrial buildings in New York State

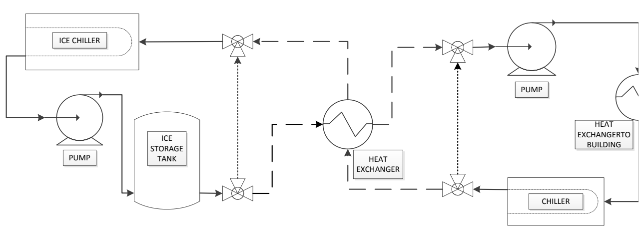

Fig. 4. Diagram of a representative ice storage system in large commercial buildings

The ice-thawing mode consists of connecting the glycol loop to the water loop via a heat exchanger in order to supplement the cooling load. As the heat transfer between the water and glycol loop takes place, the amount of ice available in the storage tank decreases. The discharging mode takes place at times when the base load chiller alone does not have the capacity to provide all of the cooling needs of the building. During these times, the base load chiller runs at full capacity; providing 30% to 40% of the peak-cooling load. This mode is used during late mornings to early evenings when the demand for cooling is highest.

The building system model provides realistic Coefficients of Performance (COP) for HVAC systems with and without ISS, which are parameterized at the nodal level for the power system simulations using the MSCOPF described in the next section.

D. Power System Modeling Using the SuperOPF

The objective criterion of the new stochastic form of MSCOPF, the SuperOPF [6], is to maximize the expected sum of producer and consumer surplus over a twenty-four hour horizon for a set of contingencies, including uncertainty about the forecasts of potential wind generation. It also allows for storage and deferrable demand. Rather than using the standard criterion of minimizing cost subject to covering physical contingencies, shedding load at a high Value of Lost Load (VOLL) is allowed if it is economically efficient to do so. This formulation determines the optimal dispatch of a set of generating units subject to their physical characteristics (e.g., rated capacity, cost and ramping capabilities) and the network's topology (e.g., transmission line constraints). The model solves the expected cost for a number of high probability cases for stochastic wind generation ("intact" states), as well as for a set of credible contingency states that occur relatively infrequently. The expected cost is minimized over the intact states and the contingency states using probabilities that reflect the relative likelihood of the different states of the system occurring. This formulation has the advantage of determining endogenously the amounts of different ancillary services (e.g., the contingency reserve and ramping reserve to mitigate wind variability) needed to meet the load profile and maintain the reliability of the delivery system [5]. The optimum dispatch is determined in the spirit of a day-ahead contract, incorporating the best available information the SO has at that time.

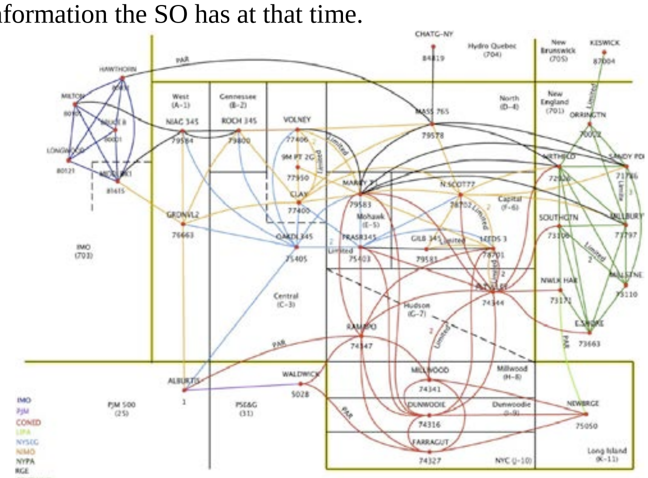

Fig. 5. An illustration of the Northeast Test Network

The empirical application of the SuperOPF uses the Northeast Test Network shown in Fig. 5 that was developed by Allen, Lang and Ilic [7]. To characterize the variability of potential wind generation in spatial and geographical terms, a clustering analysis was implemented using a *k-means++* method to determine k=4 values of wind speed (scenarios) for each hour at 16 different locations. The data were taken from the EWITS study [8], and the wind speeds were then converted to potential wind generation using a multi-turbine modeling approach [9]. This procedure makes it possible to estimate the hourly probabilities of each wind scenario occurring and the corresponding transition probabilities of moving from one scenario to another scenario in the next hour.

III. Results

The results in this section summarize the optimum dispatch pattern given a specified demand profile for a 24-hour period on a hot summer day using the network in Figure 4. Many studies of the effects of renewable generation on system costs focus on the payments made by customers in wholesale markets and the associated decrease in the energy prices when renewable energy sources are available. We have argued in earlier research that this focus ignores the financial adequacy issue for the conventional generators needed to maintain reliability and the "missing money" paid to generators in capacity markets [4]. To avoid distortions from evaluating policies solely on the average wholesale price, this analysis focuses on 1) the actual operating costs incurred by conventional generators, 2) the amount of wind generation dispatched, and 3) the maximum conventional generation capacity needed to cover the peak demand and maintain system reliability. Each simulation starts at midnight and finishes at the end of the day.

The results are presented for the following three cases:

- *Case 2*: 32GW of Wind Capacity at 16 locations.
- *Case 3*: Case 2 + 34GWh (energy capacity) of DD (thermal storage) at 5 load centers.
- *Case 4*: Case 2 + 34GWh (energy capacity) of Energy Storage Systems (ESS) collocated at the 16 wind farms.

The wind capacity represents ~20% of the system load and the variability of this resource requires the purchase of additional reserve capacity for "load following" (LF ramping reserves) as well as reserves to cover contingencies [5]. The specification of Case 3 distinguishes Conventional Demand (CD) from Deferrable Demand (DD), and two demand profiles are used as inputs. CD must be covered each hour by purchasing electricity, and DD, representing the demand for cooling services, can be met by purchasing electricity or by melting stored ice made with previously purchased electricity.

The results in Table I demonstrate that both types of storage in Cases 3 and 4 increase wind generation, lower generating costs by displacing fossil fuels, reduce ramping needs substantially, and reduce the amount of conventional capacity needed to maintain reliability. The corresponding reductions in costs are similar, including the capital cost of the conventional generating capacity.[1] Since the ESS in Case 4 is part of the supply-side, its capital cost is included in the total supply-side cost and is set equal to the capital cost of a peaking unit. The overall reduction in cost in Case 4 compared to Case 2 is relatively small ($560K/day). In contrast, the DD in Case 3 is a demand-side capability and its capital cost is covered directly by customers or by aggregators. As a result the reduction in total supply-side costs compared to Case 2 is relatively large ($9,935K/day). This reduction must be big enough to cover the capital cost of DD. It is assumed in Table I that the capital cost of DD is half the capital cost of ESS to reflect the fact that DD is not dedicated storage but an augmentation of an existing HVAC system. These assumptions imply that the overall saving for DD in Case 3 is $4,948K/day.

[1] Since the day modeled represents the annual system peak, all generating capacity is priced at the cost of a peaking unit that is assumed to operate for 100 hours/year and has a capital cost of $1760K/MW for this day.

TABLE I
SUMMARY OF THE DAILY RESULTS FOR THREE CASES

	Case2	(Case3 - Case2)	(Case4 - Case2)
Daily Summary			
E[Wind Generation] (MWh/day)	143,638	16,929	20,502
E[Conventional Generation] (MWh/day)	1,030,443	(13,621)	(17,381)
LF Ramp-Up Reserve (MW/day)	83,040	(52,435)	(54,302)
LF Ramp-Down Reserve (MW/day)	75,739	(47,561)	(45,058)
Contingency Reserve (MW/day)	88,081	(64,838)	(64,245)
Max Conventional Capacity (MW)	57,967	(4,468)	(5,062)
ESS Energy Capacity (MWh)	-	-	34,000
DD Energy Capacity (MWh)	-	34,000	-
Cost Summary ($K/day)			
E[Generation Cost]	37,115	(1,534)	(2,200)
LF Ramp-Up Reserve Cost	814	(508)	(538)
LF Ramp-Down Reserve Cost	736	(459)	(441)
Contingency Reserve Cost	429	(316)	(313)
Other Costs	1,250	46	41
Total Operating Cost	**39,179**	**(2,771)**	**(3,451)**
Capital Cost of Conventional Generators	100,004	(7,164)	(7,083)
Capital Cost of ESS	-	-	9,973
Total Supply-Side Cost	**179,528**	**(9,935)**	**(560)**
Capital Cost of DD	-	4,987	-

It is, however, important to point out that, unlike the peaking units needed to meet the peak system load, the DD and ESS will be used throughout the year for price arbitrage and to provide ramping services. In other words, the real value of DD and ESS will be larger than the results in Table I imply, and this will become apparent when the analysis covering a full year of operations has been completed.

TABLE II
OPTIMUM DISPATCH IN THE FOUR INTACT STATES FOR THE PEAK SYSTEM LOAD IN CASE 3 WITH DD

Peak Hour Supply&Demand	*Intact States*			
	Wind 1	*Wind 2*	*Wind 3*	*Wind 4*
Supply				
Conventional Generation	52783	52535	52535	52535
Wind Generation	1603	3501	5340	6226
ESS (Discharging > 0)	0	0	0	0
Import	3389	3389	3389	3389
Total Supply	**57775**	**59425**	**61264**	**62150**
Wind Spilled	0	0	0	5350
Unforced Outage	0	0	0	0
Demand				
Conventional Demand	57344	57344	57344	57344
Deferrable Demand	430	2081	3919	4468
Charging Thermal Storage	**0**	**0**	**0**	**337**
Charging Electric Vehicle	0	0	0	0
Total Energy Purchased	**57775**	**59425**	**61263**	**62150**
Discharging Thermal Storage	4038	2387	549	0
Energy for Transport	**0**	**0**	**0**	**0**
Load Not Served	0	0	0	0

It is well known that storage capacity can be used for price arbitrage to shift load from peak to off-peak periods and to reduce the amount of conventional generating capacity needed for System Adequacy. An important advantage of a stochastic MSCOPF is that it also determines the ramping services needed to mitigate wind variability. For each hour of the day, there are 12 possible states of the system, 4 intact states that reflect different levels of potential wind generation, and 8 contingency states that correspond to equipment failures. The results in Table II use the intact states at the peak load hour for Case 3 with DD as an example of how wind variability is mitigated. In Case 2 with no storage, conventional generators cover all ramping needs, and the cost of purchasing ramping reserves means that it is optimal to reduce this cost by spilling more wind. In contrast, with DD in Table II, the levels of conventional generation are similar in all four states even though wind generation increases by 4,623MWh from Wind 1 to Wind 4. This increase is offset by an increase in DD (the direct use of air conditioners) of 4,375MWh, including 337MWh recharging the DD storage, and a corresponding decrease in the discharging of the DD storage. This is why the amount of ramping reserves purchased in Table I with DD or with ESS is so much lower than it is in Case 2 with no storage.

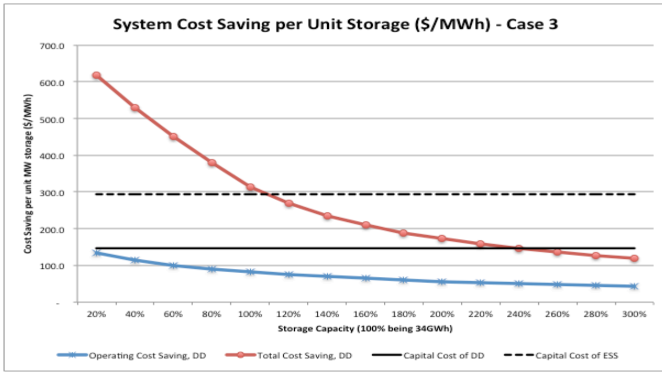

Fig. 6. Marginal savings in system costs with DD in Case 3

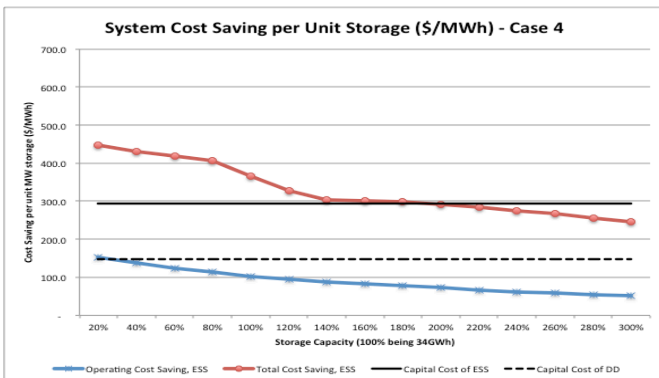

Fig. 7. Marginal savings in system costs with ESS in Case 4

The final part of the analysis is to demonstrate how quickly the marginal system savings from adding more storage declines. Figures 6 and 7 show the marginal savings in Operating Costs, including ramping costs, and in Total System Costs (Operating Costs + Capital Cost of Conventional Generating Capacity) for different levels of DD and ESS. The range is from 20% to 300% of the levels specified in Cases 3 and 4. The figures also show the specified Capital Costs of DD and ESS. The first point is that the savings in Operating Costs are not sufficient to cover the low capital cost of DD on their own in either case. Including the savings in the capital costs is essential, and if this is done, the total savings are sufficient to cover the high capital cost of ESS in both cases. For regulators, the important implication is that the owners of DD must be compensated correctly for reducing their demand at the peak system load. This means that customers should pay a demand charge that reflects their ability to reduce demand during peak system periods and not get penalized for providing ramping to accommodate more wind generation.

IV. Conclusions

This project has demonstrated the feasibility of using an integrated multi-scale modeling framework to link the demand patterns for aggregates of PEVs and ISS in buildings at the nodal level to the system performance and system costs of a test network. Both PEV and ISS represent types of DD that decouple the purchase of electricity from the delivery of an energy service. Even though the level of service delivered to customers is unaffected, managing DD optimally makes it possible to lower the system costs and customers' bills by shifting load from peak to off-peak periods, providing ramping services to mitigate the variability of wind generation, and as a result, dispatching more wind generation. The analysis in Section III uses a new stochastic MSCOPF (the SuperOPF) that optimizes the dispatch of conventional generation, wind generation and storage over a 24-hour horizon for a test network. Given the space requirements for this paper, results including the cost/damage effects of emissions from fossil-fuel generating units are not presented.

The SuperOPF treats the stochastic nature of wind generation realistically and demonstrates how this variability increases the up and down ramping reserves needed to maintain reliability. The results show that DD reduces operating costs, including ramping costs, by almost the same amount as an equivalent amount of storage (ESS) collocated at wind sites. However, these lower operating costs are not sufficient to cover the capital cost of either DD or ESS. The main saving in costs for both DD and ESS comes from the lower capital costs of conventional generating units. In both cases, the storage provides ramping to mitigate wind variability, and as a result, less conventional capacity is needed to maintain reliability.

With ESS, its capital cost is part of the supply side and will be passed on to customers in their electricity rates. The net savings are relatively small. Although customers' electricity bills will be lower with DD, they must still pay for its capital cost. We argue that this cost for DD will be lower than ESS because it is shared with the delivery of another energy service (transportation and space cooling) and the net savings for DD will be larger. However, by focusing the analysis on the day with the peak system load, the benefit of storage for the rest of the year is ignored. Hence the results presented in Section III underestimate the real value of storage to the network. The analysis for a year of operations will be completed in the near future using a new framework for doing Monte Carlo simulations.

Finally, it is important to recognize that the economic viability of DD for customers depends critically on restructuring the rates that they pay for electricity to reflect the system benefits accurately. Paying real-time prices is necessary to benefit from price arbitrage, but it is not sufficient. Demand charges should reflect the demand of customers with DD during peak-load periods, and customers should also get compensated for providing ramping services. These are challenging problems that should be addressed in future research.

V. Future Work

The current structure of the integrated multi-scale modeling framework developed in this project deals with the stochastic characteristics of generation from renewable sources and the effects on system operations. This framework addresses new problems, such as ramping costs, that are largely ignored in standard SCOPF formulations. It is sufficiently general to allow enhancements to deal with 1) including other sources of renewable energy, such as solar power, 2) including other forms of deferrable demand, such as high-temperature electric water heaters, and 3) using deferrable demand to provide additional ancillary services, such as frequency regulation. There are, however, two major issues that are closely related but also require new research initiatives that are not covered at this time.

The first issue is to determine the type of information that a system operator should provide to customers with deferrable demands and to aggregators of these customers so that they will respond in a way that lowers the costs paid by customers and is also optimal for reducing the total system costs. This is particularly important for ramping services. We assume that the huge number of customers with deferrable demand will make it unrealistic for a system operator to dispatch deferrable demand resources directly even if aggregators manage many of them. Consequently, a hierarchical structure of control with customers and aggregators operating in their own interests that also is optimal for the system is needed. Preliminary investigations show that the savings from price arbitrage using real-time prices seriously underestimate the system savings of deferrable demand compared to ESS. Even if the structure of demand charges is changed, it is not straightforward how to distinguish the ramping up component of demand from the minimum potential demand level during peak load periods. Ideally, customers should pay for the minimum demand at the peak system load, to encourage further reductions, and get paid for ramping up in response to higher levels of wind generation. One possible approach is to provide some form of ramping signal by sending data to the cloud that are accessible to customers and aggregators. The open research questions are what should this ramping signal contain, how should the ramping services provided by deferrable demand be measured, and how should customers be compensated for providing these services.

The second issue is how to extend the environmental analysis to deal with the damage effects of emissions that depend on time as well as location. With this capability it would be feasible to determine how dispatch patterns could be modified using storage and DD to reduce, for example, the severity of ozone episodes. Typically, ozone pollution is exacerbated during hot summer days when the system load is high. Potentially, storage and DD can address both of these energy and environmental challenges. Storage could be discharged more during critical periods to reduce emissions of the precursor emissions of ozone (primarily NO_x).

VI. Access to Products

The software is open source, and when the SuperOPF is sufficiently robust, it will be made available with MatPower at http://www.pserc.cornell.edu/matpower/.

VII. Acknowledgment

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VIII. Biographies

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Robert J. Thomas is Professor Emeritus of Electrical Engineering at Cornell University and a Lifetime Fellow of the IEEE. He has held sabbatical positions with the U.S. Department of Energy Office of Electric Energy Systems (EES), and at the National Science Foundation. His current research interests are the analysis and control of nonlinear continuous and discrete time systems with applications to large-scale electric power systems.

Comprehensive Educational Tools for Reliability Modeling and Evaluation of the Emerging Smart Grid (4.1)

Chanan Singh, *Texas A&M University*

***Abstract*—In the emerging environment, reliability of the power grid will be an important and challenging issue. The subject of power system reliability is thus important but a specialized one. The objective here is to develop educational material of sufficient depth so that it can be either learnt on one's own or taught by faculty who do not have sufficient expertise in this area. To achieve this, two courses have been developed. One of these is a semester long course that can be offered at the graduate level in a university either in class or as an online course. The other is a short course that can be offered in about six hours. This course could be either taken on one's own or taught by an instructor as a short course to industry.**

The semester long course has been now fully developed and has been offered twice. The power points of the short course have been almost completed but videos for explaining these power points are being developed. Both courses will be available on the internet by September, 2013.

I. Introduction

The power grid is emerging as a complex system with heavy penetration of renewable energy sources, central and distributed energy storage and massive deployment of distributed communication and computational technologies allowing smarter utilization of resources. Although it may not be clear how the shape of the grid will ultimately unfold, it is certain that it will be significantly different than the past. Not only that there will be new technologies but also different ways of monitoring, computation and control will be employed. As a result there will be higher uncertainty in the planning and operation of these systems. As the complexity and uncertainty increase, the potential for possible failures with a significant effect on industrial complexes and society can increase drastically. In these circumstances maintaining the grid reliability and economy will be a very important objective and will be a challenge for those involved. The power grid differs from many other systems that once implemented, changes can be expensive and sometimes prohibitive. Therefore, reliability of the grid cannot be left to the goodwill of those designing or planning systems nor as a byproduct of these processes but must be engineered into the grid and its subsystems in a systematic and deliberate manner. An important step in this process is to model, analyze and predict the effect of design, planning and operating decisions on the reliability of the system.

The development of the workforce for this emerging grid is important for its successful implementation. Work force needs will happen at various levels: skilled workers, engineers, managers. Our concern here is with the engineering workforce needed to design, construct and operate the future grid. The workforce must be able to produce innovative ideas and transformative changes to integrate clean and sustainable energy sources. Relevant education of this workforce is critical to the success of the future grid. Here we are acting as an enabling agent. Our objective in this work force development thrust is to develop educational material, books as well as notes, on relevant topics and on background topics required to understand these concepts, and make them available to those interested. This will make it possible to teach a variety of subjects as the availability of such material facilitates offering such courses. Consistent with the overall goals of the thrust, the objective of this task is to fill the lack of educational tools for covering the spectrum of reliability modeling and evaluation tools needed for this emerging complex cyber-physical system.

The subject of power system reliability is important but a specialized one. The objective here was to develop educational material of sufficient depth so that it can be either learnt on one's own or taught by faculty who do not have sufficient expertise in this area. To achieve this, two courses were intended to be developed. One of these was a semester long course that can be offered at the graduate level in a university either in class or as an online course. The other is a short course that can be offered in about six hours. This course could be either taken on one's own or taught by an instructor as a short course to industry.

The semester long course has been now fully developed and has been offered twice. The power points of the short course have been almost completed but videos for explaining these power points are being developed.

II. Description of Semester Long Course

Since component failures are not deterministic but happen according to probabilistic laws, this course first gives a sufficient background in probability theory and relevant knowledge of stochastic processes. To provide the ability to

The work described in this paper was made possible by funding provided by the U.S. Department of Energy for "The Future Grid to Enable Sustainable Energy Systems," an initiative of the Power Systems Engineering Research Center.

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deal with unknown and emerging modeling problems, background in general reliability analysis methods is then provided. However, over the past few decades a substantial body of methods that deal with power systems in particular has been developed. So these methods are introduced in the course. Various modules for the semester long course will now be described.

A. Introduction to Quantitative Reliability Analysis

This module explains the need for quantifying reliability and the importance of modeling and analysis. It is clear that just a qualitative definition of reliability cannot be of much value in evaluating alternative designs. When quantitatively defined, reliability becomes a parameter that can be traded off with other parameters like cost and environmental impacts.

Necessity of quantitative reliability springs from having a tool for decision making. The need is heightened by factors like ever increasing complexity of system design and operation, evaluation of alternate design proposals and cost competitiveness and cost-benefit trade off.

The module describes several measures of reliability quantification. A sample slide from the module is shown in Fig. 1 which outlines the basic measures. Another slide from this module is shown in Fig. 2 as an intuitive explanation of these measures. This module also explains how the reliability analysis can be incorporated as a constraint, part of optimization process or as an objective in multi-objective optimization.

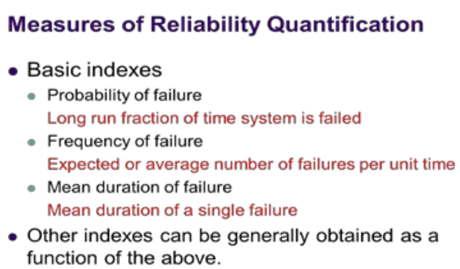


Fig. 1. A slide showing basic measures of reliability quantification

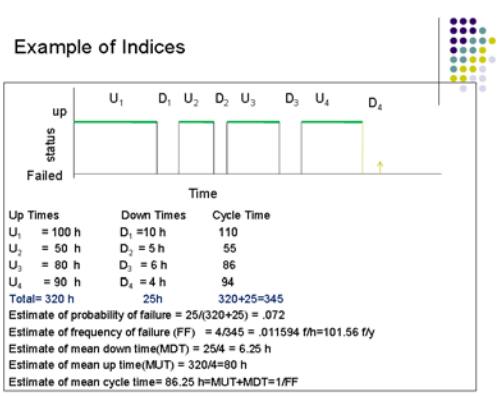


Fig. 2. A slide showing an example to illustrate basic indices

B. Review of Probability Theory and Stochastic Processes

This module has three sub-modules covering the review of probability theory and stochastic processes. The first sub-module explains the combinatorial properties of probability to find the probability of a complex event from the simpler ones. These rules are then used on a simple example to find the most commonly used index in power system reliability LOLP (Loss of Load Probability).

In the second sub-module, the random variables, probability distribution functions and their moment generating functions are described. The concept of hazard function which underlies the concept of transition rate is explained. Failure and repair rates are special examples of transition rates. At this point the conversion of transition rate into transition probability is also explained. This concept helps to discretize the continuous time Markov Processes into discrete time processes. The exponential distribution which is the most commonly used distribution function in the reliability analysis is also explained.

The sub-module 3 is focused on explaining the concept of stochastic processes. Both discrete time and continuous time Markov processes are described. Fig. 3 shows three sample slides describing simple derivation of transition probabilities.

Slide A.

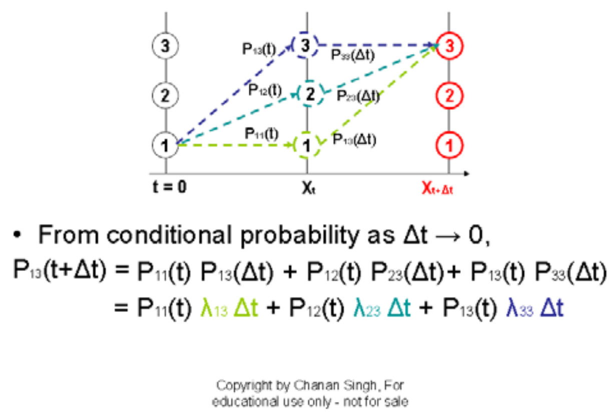


Fig. 3a. Slides A, B, C show derivation of transition probabilities in the Markov Processes

Slide B.

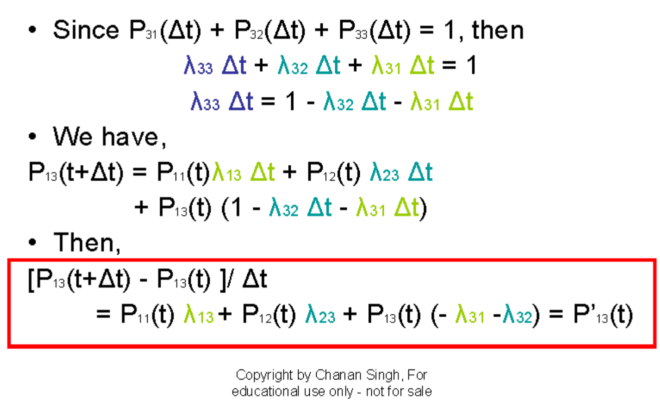


Fig. 3b. Slides A, B, C show derivation of transition probabilities in the Markov Processes

Slide C.

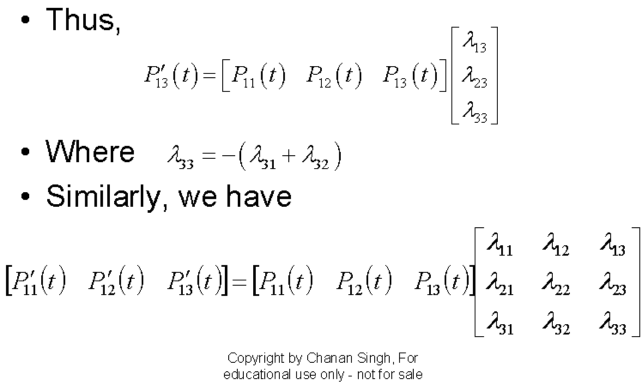


Fig. 3c. Slides A, B, C show derivation of transition probabilities in the Markov Processes

C. Frequency Balancing Approach

This module describes the difference between transition rate and transition frequency. It builds up the idea of frequency balance which is an alternative way of examining stochastic processes. The concept of equivalent transition rate is derived and used for state space reduction. This helps to make the state space more manageable for larger systems.

D. Methods of Quantitative Reliability Analysis

Two types of methods discussed are the analytical and those based on Monte Carlo simulation. These techniques are general and can be applied to any system. Within the assumptions made for the models, the analytical methods can give exact repeatable values. The analytical methods described in this material are:

State Space Using Markov Processes: This method consists in defining the states and their inter-state transitions. It is a powerful method but can run into dimensionality issues. Sequential model building by using state space reduction is described.

Network Reduction: This method consists of successively reducing the network and then finding the indices.

Min Cut Sets: This is a powerful method that can be used for both networks as well as other cases. Once the cut sets, consisting of components and conditions, have been defined, various techniques to compute indices using these min cut sets are described.

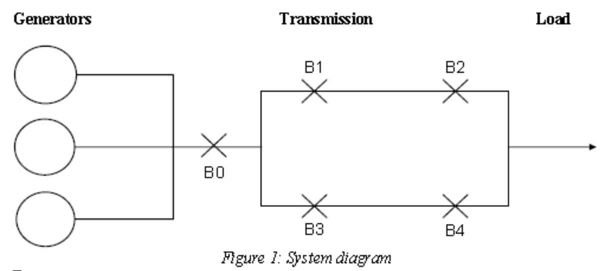
These concepts are then illustrated using a comprehensive example. The schematic of the system used for illustration is shown in Fig. 4. The course then works through by showing how the following indices are calculated:

1. Loss of load probability
2. Frequency of loss of load
3. Mean duration of loss of load

The problem is first solved by developing Markov models. First the model for generation system is developed and then reduced by merging states using the concept of equivalent transition rate. Similarly the transmission model is reduced using state merging. The original and reduced models of transmission are shown in Fig. 5. The reduced generation, transmission and load models are combined and indices calculated. The problem is subsequently solved using min cut approach for comparison.

In the Monte Carlo both the sequential and non-sequential methods are described and the unity of the underlying concepts is emphasized. Examples for implementation both the approaches are given. Fig. 6 is a snap shot of the sequential simulation using an example of two components.

EXAMPLE SYSTEM



Data

Generators:
Each generator either has full capacity of 50 MW or 0 MW when failed. Failure rate of each generator is 0.1/day and mean-repair-time is 12 hours.

Transmission Lines:
The failure rate of each transmission line is assumed to be 10 f/y during the normal weather and 100 f/y during the adverse weather. The mean down time is 8 hours. Capacity of each line is 100 MW.

Weather:
The weather fluctuates between normal and adverse state with mean duration of normal state 200 hours and that of adverse state 6 hours.

Breakers:
Breakers are assumed perfectly reliable except that the pair B1&B2 or B3&B4 may not open on fault on the transmission line with probability 0.1.

Load:
Load fluctuates between two states, 140 MW and 50 MW with mean duration in each state of 8hr and 16hr respectively.

Fig. 4. Schematic and data of the example system

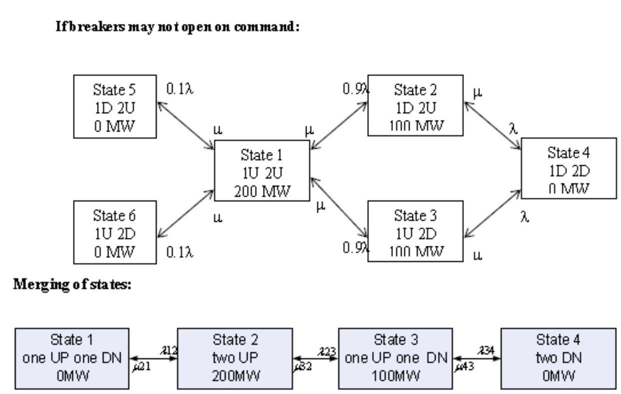
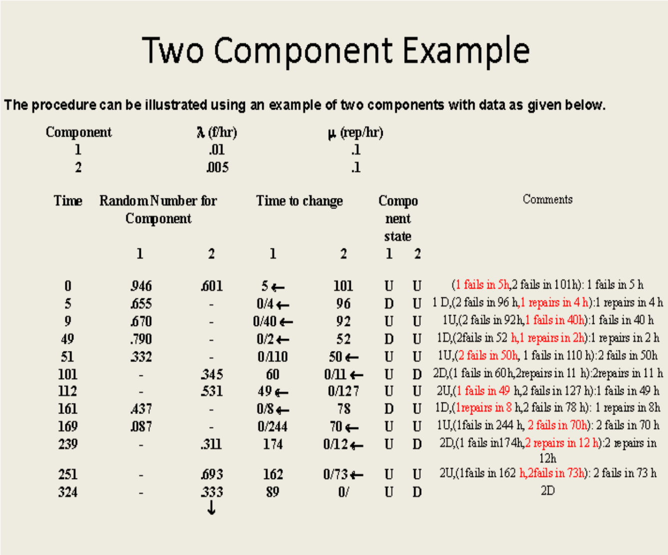


Fig. 5. Original and reduced models of transmission



Two Component Example

The procedure can be illustrated using an example of two components with data as given below.

Component	λ (f/hr)	μ (rep/hr)
1	.01	.1
2	.005	.1

Time	Random Number for Component 1	Random Number for Component 2	Time to change 1	Time to change 2	Component state 1	Component state 2	Comments
0	.946	.601	5 ←	101	U	U	(1 fails in 5h,2 fails in 101h): 1 fails in 5 h
5	.655	-	0/4 ←	96	D	U	1 D,(2 fails in 96 h,1 repairs in 4 h):1 repairs in 4 h
9	.670	-	0/40 ←	92	U	U	1U,(2 fails in 92h,1 fails in 40h):1 fails in 40 h
49	.790	-	0/2 ←	52	D	U	1D,(2fails in 52 h,1 repairs in 2h):1 repairs in 2 h
51	.332	-	0/110	50 ←	U	U	1U,(2 fails in 50h, 1 fails in 110 h):2 fails in 50h
101	-	.345	60	0/11 ←	U	D	2D,(1 fails in 60h,2repairs in 11 h):2repairs in 11 h
112	-	.531	49 ←	0/127	U	U	2U,(1 fails in 49 h,2 fails in 127 h):1 fails in 49 h
161	.437	-	0/8 ←	78	D	U	1D,(1repairs in 8 h,2 fails in 78 h): 1 repairs in 8h
169	.087	-	0/244	70 ←	U	U	1U,(1fails in 244 h, 2 fails in 70h): 2 fails in 70 h
239	-	.311	174	0/12 ←	U	D	2D,(1 fails in174h,2 repairs in 12 h):2 repairs in 12h
251	-	.693	162	0/73 ←	U	U	2U,(1fails in 162 h,2fails in 73h): 2 fails in 73 h
324	-	.333 ↓	89	0/	U	D	2D

Fig. 6. Example illustrating sequential simulation for two components

E. Introduction to Power System Reliability

This module provides an overall view of power system reliability evaluation. Functional zones for power system reliability evaluation are described. Then the deterministic as well probabilistic indices that have been proposed are discussed. Fig. 7 is a slide of an example of description of the relationship between loads, generation to create the loss of load events.

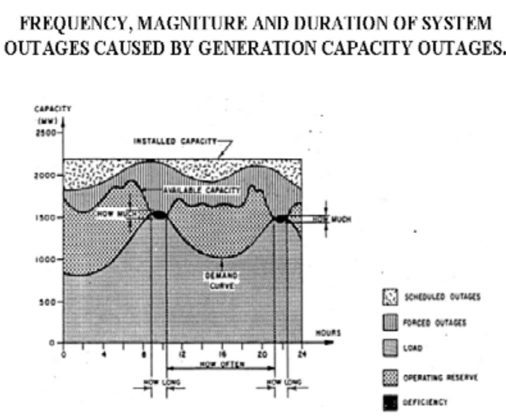


Fig. 7. Frequency, magnitude and duration of outages

F. Single Area Generation Reliability

Single area problem typically means generation adequacy problem. In this the transmission constraints are not included and the emphasis is on having adequate generation for planning (static reserve) or operation (operating reserve). This has three sub-modules dealing with discrete convolution methods, continuous distribution approximation and spinning reserve determination.

Discrete convolution models:

In reality, the models for the generators are discrete capacity models since discrete levels of capacity are associated with various states. Unit addition method which is typically used to combine the unit models to form the generation system model is described. An efficient method for building load model is also discussed. A method for combining load model with the generation model is also described. Emphasis is placed on computing LOLE, Frequency and Duration of load loss and EUE (Expected Unserved Energy).

Continuous distribution approximation:

Methods have been developed to approximate the discrete models using continuous distributions. These methods can be faster than the discrete convolution but with the more efficient implementation of unit addition algorithms, the advantage appears to have diminished. One such method is described in the course.

Spinning reserve:

Spinning reserve determination methods are described. The basic PJM method and modifications of this method are described. A short description of frequency and duration method of dealing with operation reserve is also discussed.

G. Multi-Area Reliability

In the traditional single area model, intra-area transmission constraints are ignored. Interpreted in another way, transmission lines are assumed to be capable of transferring power from generation to load points without any problem. In multi-area model inter-area transmission constraints are considered. The intra-area constraints are only indirectly considered since they impact the inter-area tie capacity. The conceptual idea of single and multi-area models is shown in Fig. 8.

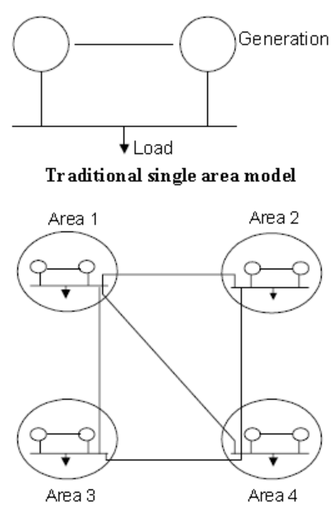


Fig. 8. Multi area model vs. single area model

There are four sub-modules for multi-area. Three sub-modules discuss the analytical methods for multi-area evaluation, both for looped as well as radial configurations. The fourth sub-module discusses the Monte Carlo method as applied to particular commercial software.

H. Composite System Reliability

This module discusses the models and methods for composite system reliability evaluation. The composite system and multi-area system problem are similar in many ways as they are both multi-nodal. The major difference is in the number of nodes, the modeling of the transmission network and the power flow models used for state evaluation. Because of more detailed network model, the composite system reliability model has many more nodes than the multi-area model. Network flow model (transportation type) and DC flow methods are considered adequate for multi-area reliability evaluation but DC flow or AC flow methods are considered adequate for composite system reliability evaluation.

This module first describes the component models. Then a contingency ranking based method is discussed. Subsequently the Monte Carlo simulation method is described in detail. Convergence criteria for Monte Carlo are discussed and three variance reduction techniques are described.

I. Integration of Renewable Energy Sources

The renewable sources such as wind and solar are fluctuating in nature and thus cause special issues for the grid reliability. This module describes these issues and how to model their impact on the grid. The contents of this module can be appreciated from the first slide shown in Fig. 9 that shows the outline of this module.

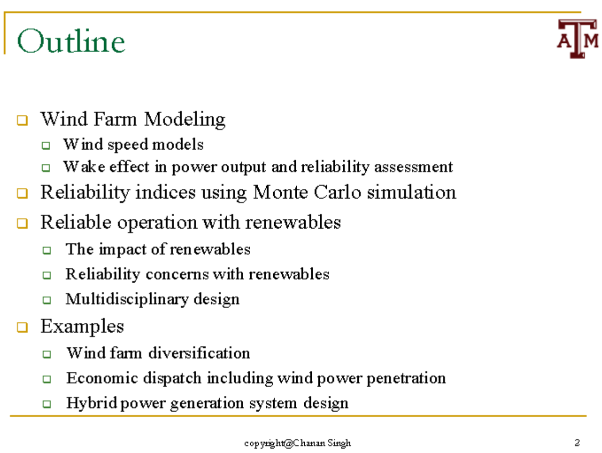


Fig. 9. Outline of the module

J. Reliability Evaluation as Cyber-Physical Systems

This is an emerging topic and not much appears to have been done. This lecture attempts to outline the issues and propose a method based on the concept of interface matrix. The contents of the module can be partly appreciated from the slide in Fig. 10 giving the outline.

III. Description of Short Course

The short course consists of seven modules which have similar content to the semester long course but are briefer. A short description of the seven modules is provided.

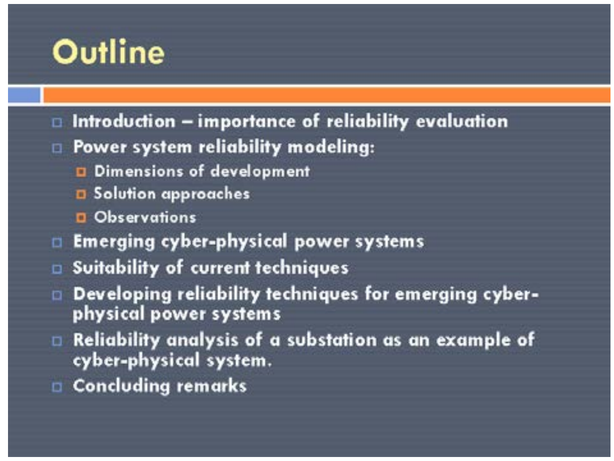


Fig. 10. Outline of the cyber-physical lecture

A. Introduction to Quantitative Reliability Analysis

This module explains the need for quantifying reliability and the importance of modeling and analysis. This module is almost the same as the one for the full semester course.

B. Review of Probability Theory

This module provides a basic review with applications to power system reliability. The topics covered are definitions of sample space or state space and events. The various operations on events are described and the calculation of probability of an even is discussed. Then these ideas are applied to a simple system shown in Fig. 11 to calculate LOLP.

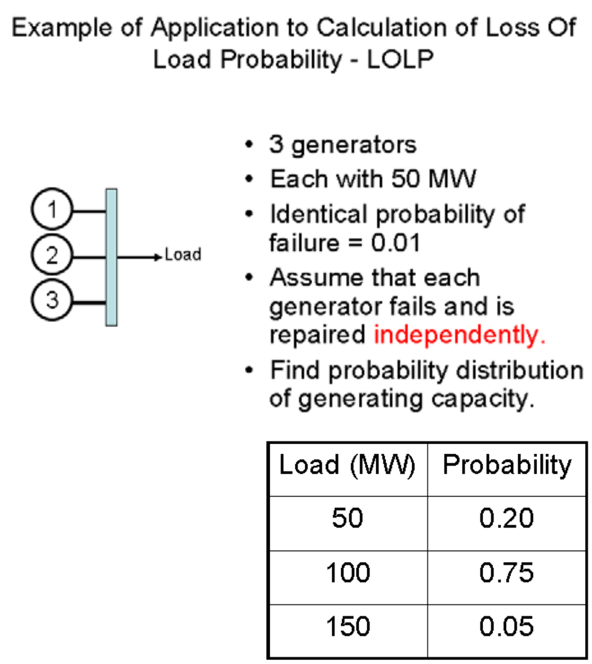


Fig. 11. Example system

C. Introduction to Power System Reliability

This module provides an overall view of power system reliability evaluation. The overview describes both the parts of system coverage as well as solution approaches used. A sample slide showing general schematic is shown in Fig. 12.

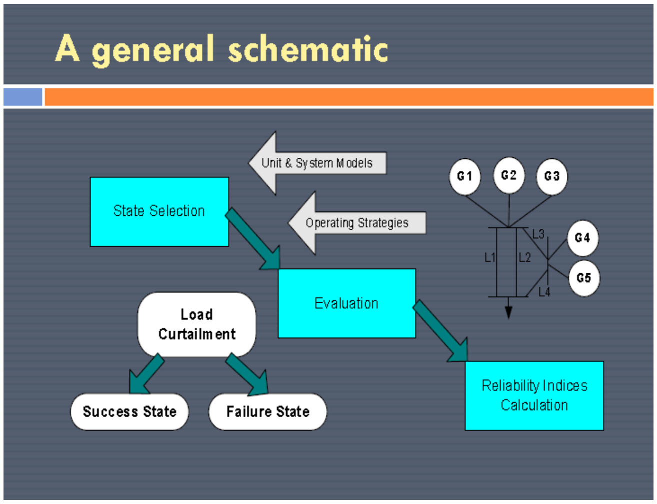


Fig. 12. Schematic of reliability evaluation

D. Single Area Reliability Analysis

Basic concepts of generation adequacy analysis are covered and illustrated with an example using hand calculations.

E. Multi-Area Reliability

The multi-area problem is formulated and the various approaches to solution are outlined. It is emphasized that most commercial programs use Monte Carlo simulation which is described in the next lecture.

F. Monte Carlo Simulation

This module describes how Monte Carlo simulation works as it is useful for both the multi-area as well as composite system reliability evaluation.

G. Composite Power System Reliability Evaluation

This module describes models and methods for composite system reliability evaluation.

IV. Results

Semester long course has been taught in Fall 2012 at Texas A&M University. There were around 30 students and feedback was excellent. The students reported:

- The course is important for engineers and they expect it will help them in the future.
- They felt it was well structured.
- Some said this was the most important material they had and they learnt something new they never saw before.

Short course in a somewhat different version was taught at one of the major ISOs and was attended by the engineers and some board members. It was also well received.

V. Conclusions

There is a need to have a well-educated work force for managing the complexities of the future grid. Reliability assurance of the future grid is an important topic. Before decisions are made one needs to estimate the impact of such decisions on the reliability of the system. For studying the impact of planning and design decisions on reliability, one needs to be able to model and simulate the system. In the absence of such analysis, we can end up with systems that may require expensive retrofit solutions.

These two courses will provide the tools to educate this work force about reliability modeling and evaluation of systems. The semester long course can be taught to graduate students or senior undergraduates. This can also be used for self-learning together with using some reference material. The short course is for self-learning or teaching to industry. The estimated time to teach this course is one day.

The benefits of developing and teaching these courses are a workforce trained in reliability modeling and analysis that will lead to better design and planning resulting in systems which are balanced in reliability and cost.

VI. Future Work

So far as the short course is concerned, a video has been developed to explain the first module. Videos for the other sections will also be developed. For the semester long course, slides with sufficient detail have been developed. Developing accompanying videos will be useful but time consuming. These videos can be developed if more funding is available.

VII. Access to Products

Both course materials will be available on the internet and freely available to anyone in the world. For reasons of easy maintenance and updates, the primary residence will be at the Task leader’s website at Texas A&M University: http://www.ee.tamu.edu/People/bios/singh/index.htm. However, there will be a link provided to the PSEC Website.

VIII. Acknowledgment

The author would like to thank all the graduate students who took this course and provided feedback for its improvement.

IX. References

Project Publications to Date:

Singh, Chanan. “Workforce Development for the Future Grid to Enable Sustainable Energy Systems.” Proceedings of the IEEE PES General Meeting, San Diego, July 2012. E.

X. Biographies

Chanan Singh(S’71–M’72–SM’79–F’91) is currently Regents Professor and Irma Runyon Chair Professor in the Department of Electrical and Computer Engineering, Texas A&M University, College Station, USA. His research and consulting interests are in the application of probabilistic methods to power systems.

Dr. Singh is the recipient of the 1998 Outstanding Power Engineering Educator Award given by the IEEE Power Engineering Society. For his research contributions, he was awarded a D.Sc. degree by the University of Saskatchewan, Saskatoon, SK, Canada, in 1997. In 2008, he was recognized with the Merit Award by the PMAPS International Society. In 2010, he was the inaugural recipient of the Roy Billinton Power System Reliability Award.

Critical Infrastructure Security: The Emerging Smart Grid (4.6)

Anurag K Srivastava, Carl Hauser, and Dave Bakken
Washington State University

***Abstract*—An educated and trained workforce is the key to realizing the smart grid vision. The increasing convergence of power, communications, and information networks is creating a need for new, multi-disciplinary skill sets for power industry employees. Furthermore, an aging and retiring workforce adds to this challenging problem. A new course has been developed at Washington State University as a step towards providing the needed interdisciplinary training. The course is team-taught by power and computer science faculty members and intended for seniors and graduate students from computer science and engineering.**

The semester long course has been fully developed and has been offered twice. This paper describes the course details along with our experience in offering this course in-class and online. Course material will be available online in summer 2013.

I. Introduction

THE future electric grid will look very different from that of the past, with integrated renewable energy, active loads, storage devices and enhanced ability to monitor and control. The smart electric grid will be more controllable and interactive compared to the existing electric grid and it creates a need for training and workforce development to deal with the evolving complexity [1].

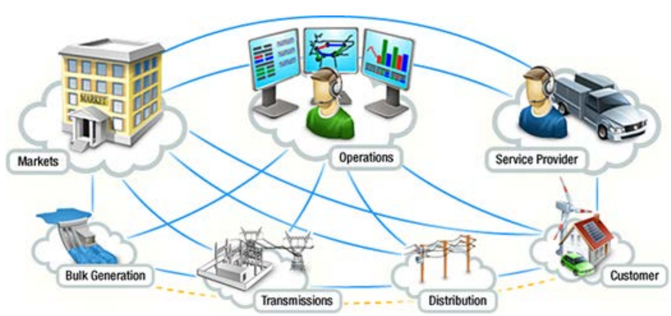


Fig. 1. Communication and information layer enabling physical layer to be 'smart' (Credit: NIST)

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We gratefully acknowledge the contribution of Prof. Min Sik Kim to the development and teaching of the 2012 offering of this course. Although he is no longer involved in the project the security module of the course is principally of his design.

A next-generation electrical power system will be typified by the increased use of communications and information technology in the generation, delivery and consumption of electrical energy. Increased use of communication and information technology as shown in Fig. 1 will help in attaining self-healing capability leading to enhanced reliability, efficiency and security [2].

An educated and trained workforce is the key to realizing the smart grid vision. The increasing convergence of power, communications, and information networks is creating a need for new multi-disciplinary skill sets for power industry employees. Furthermore, an aging and retiring workforce adds to this challenging problem. A generation gap has developed in the electric power industry, resulting from years of low hiring levels in its professional ranks. The Center for Energy Workforce Development estimates that roughly 53% of engineers at electric utilities may retire in the next 10 years, based on a survey conducted in 2011 as shown in Fig. 2. In 2006, the North American Electric Reliability Corporation (NERC) identified in it's long-term reliability assessment report that the aging workforce and the potential loss of expertise due to retirement is one of the main challenges to maintaining reliability of the electricity supply. Authors of this article frequently receive emails from power industry employers with a "desperate" need for "smart grid engineers," with a strong multi-disciplinary background.

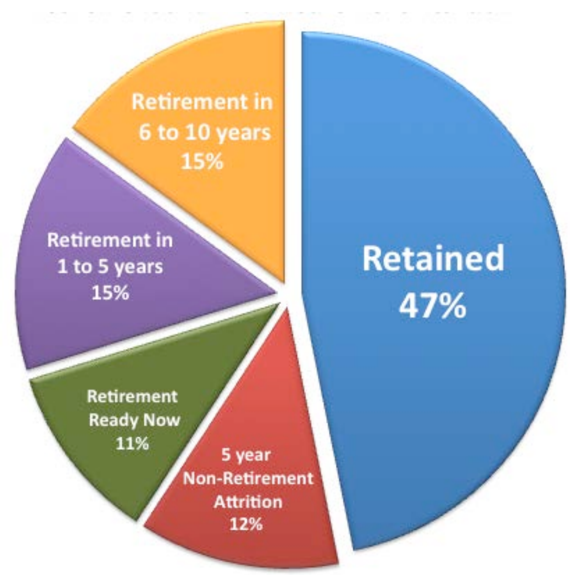

Fig. 2. Potential replacement impact on retirement and non-retirement attrition for engineers (Credit: CEWD)

To meet growing demand, electric utilities face increasing challenges in providing a reliable supply of electricity. The existing grid infrastructure is aging with many components approaching the end of their life cycle after decades of service. In addition, the power grid must grow and evolve to accommodate renewable/sustainable and variable energy sources on the generation side and to support dramatically different demand profiles from new uses such as plug-in electric vehicles on the load side.

Educational institutions have a similar workforce problem as industry and NERC noted a parallel "decline in the number of college professors able to teach power system engineering and related subjects" in its 2007 report.

Like the electric power grid itself, power engineering courses at most universities have changed little over the past several decades. This creates a need for workforce development efforts and training in interdisciplinary technical areas used in smart grid development. Existing educational programs and curricula need to be evolved to fit the need of students, faculty and employers for a workforce that is capable of deploying and operating the smart grid. Also, power engineering operation and design problems need to be explained in different ways to be understandable by non-power engineers, who will participate in development and implementation of the smart grid. Designing such an interdisciplinary curriculum is challenging for faculty members who themselves do not possess those interdisciplinary skills.

There are numerous efforts in place to deal with smart grid workforce development. Some of those include creating pipeline of pre-college students by outreach, motivating college students by challenging them with an important national problem, industry-university collaboration, and modernizing existing curricula at universities. A number of organizations including the IEEE Power and Energy Engineering Workforce Collaborative, the Center for Energy Workforce Development, the U.S. Department of Energy, the National Science Foundation, and the Power System Engineering Research Center, in collaboration with industry and university members, have been leading these efforts.

Recently, the U.S. Department of Energy announced awards supporting workforce training initiatives. These multi-million awards focused on developing and enhancing workforce training programs for the electric power sector and also on supporting Strategic Training and Education for cross-disciplinary electric power system programs at both the universities and colleges. Additionally, projects were funded for smart grid workforce training projects for new hires as well as retraining programs for electric utility workers focusing on smart grid technologies and their implementation. Using funding available from Department of Energy (DOE) through Power System Engineering Research Center, an interdisciplinary course focused on the cyber-security aspects of the smart grid has been developed at Washington State University.

II. Course Description

The course developed in this effort is team taught by authors of this article and titled, "Critical Infrastructure Security: The Emerging Smart Grid". The course was first offered in Spring 2012 and the second offering occurred in Spring 2013.

A. *Course Objectives*

Our objectives in creating this course were:

- Design a course with multi-disciplinary content integrating topics from data communication, computing, control, cyber-security and power systems that are relevant to secure operations of smart grids.
- Design a course targeting an audience of senior undergraduate and graduate engineering and computer science students.
- Design a course that could be offered to online distance engineering students or engineers from industry as well as in the conventional classroom setting.
- Design course materials to be easily adopted by instructors at other schools.
- Design course evaluations that allow us to assess course outcomes and improve the content.

B. *Course Contents*

The course has four principal components: smart grid operation and control; communication; data management and computing; and basics of cyber-security as shown in Fig. 3.

After taking this course, students are expected to be prepared to contribute to security aspects of industrial projects related to the electric grid. Students will be able to understand vulnerabilities and the threats to the power grid and associated infrastructure in addition to understanding the basic principles of smart grid components and operation. Students are expected to critically analyze the interdependencies of related infrastructure in smart grid and apply the interdisciplinary principles that they have learned in this class to building the smart grid.

The course is a conjoint senior undergraduate and graduate course in which both sets of students attend the same lectures, but graduate students are given additional homework problems. We have designed the course for both on-campus classroom delivery and distance delivery (using recorded lectures, on-line notes, and web-based homework submission and/or grading), thus making it available to engineers in industry. The course does not rely on either computer science or EE prerequisites and is available to students in both majors, but we attracted far greater EE than CS enrollment. We hypothesize that for most CS students, taking a more advanced class on the security topics covered here will be perceived as more valuable than study in a single specialized field of potential employment.

In the power engineering part of the course, basics of voltage-current relationship with real and reactive power are discussed. Fundamentals of power system components and the general operational paradigm of *sense*, *communicate*, *compute, visualize and control* are discussed for normal operation. Things that can go wrong during power system operation are discussed next, with emphasis on root causes like lightning, wind and snow, deterioration (insulation failure), animals, trees, accidents and man made errors (mistakes). Past and recent power blackouts around the world are discussed and findings from blackout investigation committees with main root causes are listed. Recommendations from blackout investigation committees serve as excellent motivation for students to study cyber physical system aspects of the smart electric grid.

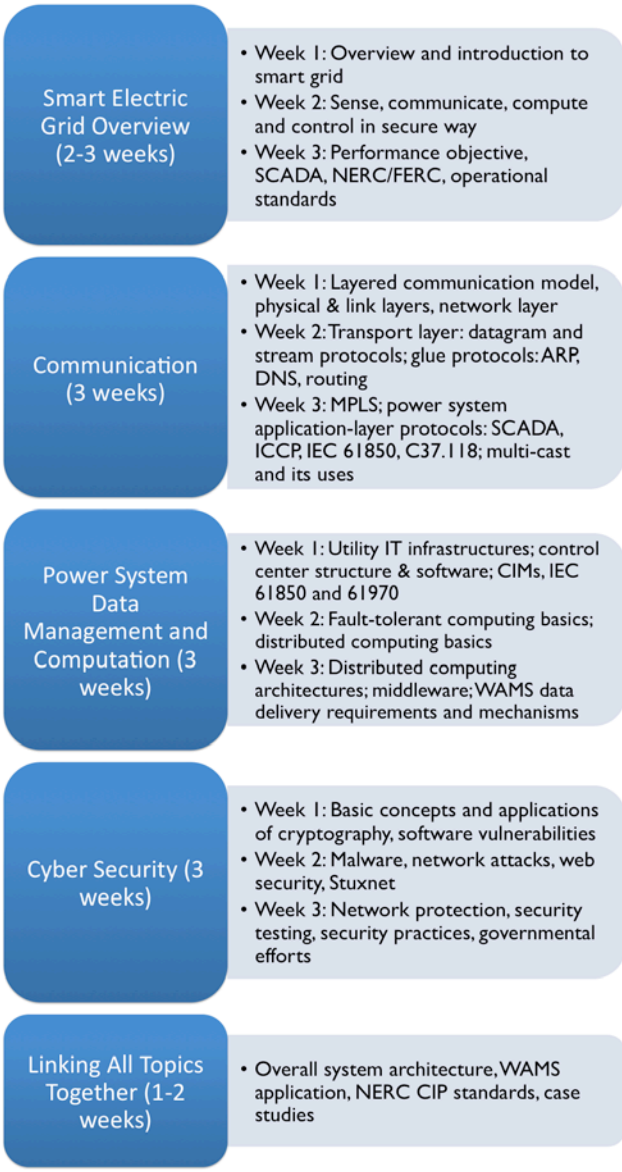

Fig. 3. Course topics covered

Level	Area Covered	Management	
Interconnection	Country	WA-EMS	Wide-Area EMS
ISO/Control Area	State/Region	EMS	Energy Management System (EMS)
Distribution Utility	County/City	DMS	Distribution Management System
Microgrid	Campus, Neighborhood	μGEMS	Microgrid EMS
Building/Facility	Block, Lot	BEMS	Building EMS
Home	Lot	HEMS	Home EMS
Appliance	Room/outlet	DPM	Device Power Management

Fig. 4. Energy management and geographical scale

NIST smart grid conceptual model was used as building blocks to explain different infrastructure layers in smart electric grid. Key differences between existing and future smart grid are explained using DOE published reports.

The time scales involved in power system dynamics are introduced leading to discussion of the communication requirements needed for analyzing power system dynamics at these different time scales. Discussion of time scales for several different applications in energy management systems also set up more discussions of communication requirements. Geographical scales for system operation also impact communication requirements as shown in Fig. 4. NERC reliability regions are introduced to help students achieve better understanding of all of these requirements. Finally, the roles of the Federal Energy Regulatory Commission and the North American Reliability Corporation in establishing power grid reliability were discussed. Examples of smart grid standards including C37.118 and ANSI C12 are also discussed. Students are introduced to several smart grid projects funded by the U.S. Department of Energy towards end of the semester.

The communication part of the course provides an overview of Internet technologies and introduces the idea of a *protocol stack* then covers in some detail the application, transport, network, link and physical layers of the Internet protocol stack. Performance criteria including loss, delay, and throughput are also covered. Impacts of various design choices at the link layer, network layer and transport layer are discussed in detail as they pertain to the smart grid. In the first offering of the course material students used a textbook, “Computer Networking: A Top Down Approach”, by Jim Kurose and Keith Ross (5th edition, Addison-Wesley, April 2009). The second offering use of the textbook was replaced by additional Internet resources at a somewhat more basic level as many students did not find the textbook useful enough to justify the expense of purchasing it.

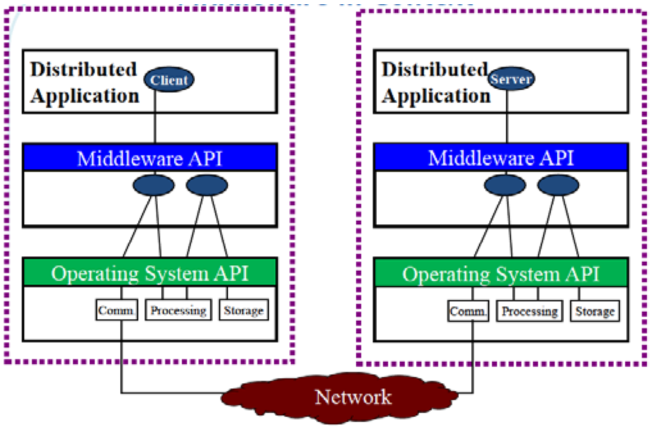

Fig. 5. Middleware and distributed applications

The data management and computation part of the course covers control center evolution, utility IT infrastructure and software tools. The Common Information Model and standards like IEC 61970 are introduced. Distributed computing basics, fault tolerance basics, and middleware are discussed as shown in Fig. 5. Further applications of middleware in data delivery and the ideas involved in creating a NASPInet for wide area data delivery are discussed.

In the last part of the course, students are introduced to the basic tools of cyber security, which are then related to the smart grid. Key security concepts are *confidentiality, integrity and availability*. Cryptography and authentication are tools for achieving them. The course then introduces the ways that cyber systems' security is often compromised: software vulnerabilities, network attacks, followed by discussion of the protection mechanisms and security practices that are used to prevent and mitigate those compromises. Finally, the Stuxnet attack was discussed as case study.

This first course offering (Spring 2012) used both face-to-face and online delivery. The course met two times a week with each lecture being approximately 75-minutes. The live lectures were captured using the *Tegrity* lecture capture software for use in the online course sections. The *Angel* course management system available from WSU media services supported delivery and collection of homework assignments, quizzes, exams and term projects. The course had 3 homeworks and 2 quizzes done individually by students, and a mid term exam, a final exam and a group project all done by group of students. Group activities were required in order to increase the interaction among electrical engineering and computer science students. There was no single textbook, and a combination of chapters from different books and online material were used as references for this course. Additional class notes were provided to students.

TABLE I
CLASS COMPOSITION OF FIRST COURSE OFFERING IN SPRING 2012

Face-to-face			
Undergraduate (Computer Science)	Undergraduate (Electrical Engineering)	Graduate (Computer Science)	Graduate (Electrical Engineering)
7	4	1	11

TABLE II
CLASS COMPOSITION OF FIRST DISTANCE OFFERING IN SPRING 2012

Distance Campus		Online Audit
Undergraduate (Computer Science)	Graduate (Computer Science)	
4	2	24

The classroom offering of the course in Spring 2012 had the student composition shown in Table I; the distance offering had the composition shown in Table II. Table III shows examples of some of the group projects submitted by students. As shown in Table III, students worked on very diverse topics having an interdisciplinary nature. As part of the class policy, each project team had a mix of computer science and electrical engineering as well as undergraduate and graduate students. Students from the distance campus collaborated with in-class students to form teams for the project, mid-term and final exams. Project topics were required to relate to the intersection of the power grid and at least one of these topics: communication, data management, computing and cyber security.

Students were required to submit a final project report, which could be either a critical review of chosen references or simulation work related to chosen topic (example: false injection of data in state estimation). A minimum of 5 references were required coming from IEEE transactions, magazines, proceedings or SmartGridComm conference papers. For all team tasks, students were required to submit evaluations of contributions from each team member.

TABLE III
SAMPLE OF GROUP PROJECTS CHOSEN BY STUDENTS

1	Security Vulnerabilities in Control Systems and the Grid
2	Smart Meters: A review of issues, cases and solutions
3	Communication Links and Delays in Wide Area Measurement Systems
4	Stuxnet: Dissecting the malware and it's effect
5	The Smart Grid and Software Defense Mechanisms

The in-class student composition of the second offering of the course (Spring 2013) is shown in Table IV and distance student composition in Table V. Also, this year, there was a lower percentage of CS students compared to spring 2012 offerings. In the distance section, there were only EE students ffor 2013 in contrast to 2012 when there were only CS students. For 2013 offerings, the course again met two times a week for 75-minutes lectures. The course was offered online using the same software tools as 2012 offerings. The course had 4 individual assignments and 2 individual online quizzes, and one mid term group exam, one final group exam and one group project. Faculty members tried to integrate more case studies in this course offering.

TABLE IV
CLASS COMPOSITION OF SECOND COURSE OFFERING IN SPRING 2013

Face-to-face			
Undergraduate (Computer Science)	Undergraduate (Electrical Engineering)	Graduate (Computer Science)	Graduate (Electrical Engineering)
2	2	3	15

TABLE V
CLASS COMPOSITION OF SECOND DISTANCE OFFERING IN SPRING 2013

Distance Campus		Online
Undergraduate (Electrical Engineering)	Graduate (Electrical Engineering)	
4	0	0

III. COURSE ASSESMENT

Students' feedback and evaluations of the 2012 offering were taken into account to improve the course contents and organization in future offerings. Students' performance on assignments, quizzes, exams and a project will be another measure to meet the learning objectives of this course. 15 out of 27 students completed the course survey in spring 2012. Based on course evaluation, 33% students found it excellent, while 40% found it good. Table VI shows the rating given by students.

TABLE VI
OVERALL RATING OF COURSE BY STUDENTS

Excellent	Good	Neutral	Poor
33%	40%	13%	13%

TABLE VII
STUDENTS BELIEVE THEY LEARNED DURING THE CLASS

Very often	Sometime	Few Times	Never
80%	7%	13%	0%

Students indicated that course slides and lectures as well as group work helped them most to learn. One of the students indicated, "The approach by all the professors involved a lot of multimedia and relevance to real life situations. When you read about something in the news and have a comment on it because of a course you are studying, half the battle is won. That was the impact this course had". Some of the students were overwhelmed with diverse information in a single class. It was hard to develop expectation in class due to multiple faculty members. Some of the students indicated that they obtained internship or employment in the power industry based on having taken this course. Table VII shows feedback from students based on 'how often they believe they have learned during the class'.

Table VIII shows students' feedback on how well the course was organized and 93% students agreed that the course was well organized. On a question related to connecting course material to real world problems, 87% of students agreed or strongly agreed.

TABLE VIII
COURSE ORGANIZATION

Strongly agree	Agree	Neutral
47%	46%	7%

TABLE IX
CONNECTING COURSE MATERIAL TO REAL WORLD PROBLEM

Strongly agree	Agree	Neutral
67%	20%	13%

For the faculty members, this was a challenging class to design and teach given such a diverse set of students. It was difficult to design lectures that would engage computer science and electrical engineering students at same time. Overall it was a fun course with its own challenges. We were particularly pleased with the learning evidenced by the group projects at end of the class. Course materials developed in this project will be disseminated through conference/journal papers and as freely redistributable contents.

For the 2013 offerings, which are still under way, the authors are designing an additional course assessment survey to examine the effectiveness of the design of the multidisciplinary tasks in the Smart Grid course and to determine the extent of student collaborative learning in the course. The primary expected outcome of this survey will be to improve future offerings of the course and evaluate the design of the current offering. The survey is being designed with help of a faculty member from the WSU department of education. The Institutional Review Board (IRB) is currently reviewing the designed survey. This new set of survey questions is specifically designed to assess the effectiveness of the course offerings for EE and CS student and goes beyond the standard course assessment at Washington State University.

IV. RESULTS

This course was offered in the Spring of 2012 and 2013. It was team taught and offered to online distance engineering students and engineers from industry as well as in the conventional classroom setting. Course materials will be first available in the summer of 2013 with updates occurring as the course is repeated.

V. CONCLUSIONS

A new smart grid course has been development at Washington State University in line with the need for interdisciplinary training to support the smart grid. This course covers communication, computation and control aspects of the smart grid emphasizing cyber-security aspects. After taking this course, students are expected to contribute to security aspects of industrial projects related to the electric grid. Students will be able to understand vulnerabilities and the threats to the power grid and associated infrastructure in addition to understanding the basic principles of smart grid components and operation. Students are expected to critically analyze the interdependencies of related infrastructure in smart grid and apply the interdisciplinary principles that they have learned in building the smart grid.

The audience for the course and materials is undergraduate and graduate students in engineering and computer science as well as university-level instructors. Students' feedback shows high learning outcome of this course and ability to address real world problems.

VI. Future Work

Based on students' feedback, this course will be taught in the future with more focus on case studies and then teaching related fundamentals needed for understanding specific case studies. Also, faculty members will be using their own notes instead of using a collection of chapters from different books. Relevant reading material will be provided in advance to allow going in more depth in course material in the class. Case studies examples being considered include i) AMI and its smart grid role and coupled with a detailed discussion of IP/UDP, symmetric key encryption and ii) monitoring and control, discussing SCADA, DNP3, along with encapsulation of protocols in IP/TCP. Also, we will try to design course having more unique material instead of extensively borrowing content from existing courses.

In the future, we will have separate offerings for the face-to-face class and the online class. The online class will be offered by WSU Global Campus.

VII. Access to Products

The course described here can be adopted for smart grid cyber security education by other faculty members. All the developed materials will be available through a restricted website in summer 2013 and can be requested by faculty members. There will be a link provided on the PSERC Website. Also, any interested students can take this course using WSU Global Campus online offerings.

VIII. Acknowledgment

The author would like to thank all the graduate students who took this course and provided feedback for its improvement.

IX. References

Project Publications to Date:

[1] Srivastava, Anurag K.; Carl Hauser, David Bakken, and Min Sik Kim. *Design and Development of a New Smart Grid Course at Washington State University*. IEEE PES General Meeting, San Diego, CA, July 2012.

[2] Srivastava, Anurag K.; Carl Hauser, and David Bakken. "*Study Buddies*", IEEE Power and Energy Society Magazine, vol. 11, issue 1, pp. 39-43, Jan. 2013

X. Biographies

Anurag K. Srivastava (S'00, M'05, SM'08) received his Ph.D. degree in Electrical Engineering from Department of Electrical and Computer Engineering, Illinois Institute of Technology, Chicago, USA in 2005 and M.Tech. and B.Tech degree from India. He is working as Assistant Professor at Washington State University since August 2010. In the past, he worked as Assistant Research Professor at Mississippi State University during 2005-2010. Before that, he worked as Research Assistant and Teaching Assistant at Illinois Institute of Technology, Chicago, USA and as Senior Research Associate at Electrical Engineering Department at the Indian Institute of Technology, Kanpur, India as well as Research Fellow at Asian Institute of Technology, Bangkok, Thailand. His research interests include power system operation and control, power system modeling and real time simulation, electricity market and engineering education. Dr. Srivastava is a senior member of IEEE and member of IET, ASEE, IEEE Power and Energy Society (PES), Sigma Xi and Eta Kappa Nu. He is chair of IEEE PES career promotion subcommittee, vice-chair of IEEE PES student activities and active member of several other PES technical committees. He is the recipient of numerous awards including IEEE best paper award and author of more than hundred technical publications including a book.

Carl H. Hauser is an Associate Professor of Computer Science in the School of Electrical Engineering and Computer Science (EECS) at Washington State University (WSU). His research interests include concurrent programming models and mechanisms, networking, programming language implementation, and distributed computing systems. Prior to joining WSU, he worked at Xerox Palo Alto Research Center and IBM Research for a total of over 20 years. He holds degrees in computer science from Washington State University (B.S., 1975) and Cornell University (M.S., 1977, and Ph.D., 1980).

David E. Bakken as an Associate Professor of Computer Science at WSU/EECS. His research interests include wide-area data delivery mechanisms for power grids (for the last 13 years), new kinds of middleware, and fault-tolerant distributed computing. He is co-chair of the WAMPAC symposium for IEEE SmartGridComm 2012. Prior to joining WSU he was a research scientist at BBN. He holds a BS degree in mathematics (1985), and degrees in computer science from WSU (BS 1985) and the University of Arizona (MS 1990 PhD 1994). Prior to Arizona he worked for Boeing, and he has consulted to Amazon.com, Harris Corp, Real-Time Innovations, and others.

Energy Processing for Smart Grid (4.4)

James Momoh, *Howard University*

***Abstract*--The overall need is to re-energize the interest in power system engineering. Educational material is needed for teaching renewable energy, storage facility, energy processing, measurement techniques, and smart grid technologies/systems. There is a need to develop a university course on smart grid energy processing to equip students for the future workforce. This university course is for undergraduates and first year graduate students in the field of power engineering.**

I. Introduction

A number of colleges and universities currently offer electric machinery (energy conversion system) as a fundamental course on power system. This course however fails to address new topics required for efficient operation and control of the future power system. The future grid has to overcome the weakness of the existing grid. To do that it must be smart, sustainable, adaptive and resilient to attack. Therefore, there is a need for the future work force to be knowledgeable of state of the art components of the future grid such as Renewable Energy Resources (RER), measurements, control tools, power system communication system, standards and computational tools. The new course “Energy Processing and Smart Grid” is aimed at equipping students in Electrical and Computer Engineering curriculum with the theoretical and practical know how for energy processing for smart grid.

It is assumed that students taking this course already have foundation knowledge in network analysis and electromagnetic field theory. However, to accommodate students with a weak foundation in power system principles, the course content is structured in a flexible and modularized manner to include energy conversion concepts as part of the “energy processing and smart grid” course. The course is aimed at seniors focusing on power system as electives and 1st year graduate student. In support of this course, a book that includes ample numerical examples, case studies and problem will be developed. Also included is a laboratory that allow the student hands-on experience on some smart grid functionalities. To this extent a faculty approval was obtained last semester at Howard University to introduce a new course: fundamental of energy system being offered this semester to juniors. The course content is outlined in Table 2. This course was extracted from the energy processing for smart grid course.

The work described in this paper was made possible by funding provided by the U.S. Department of Energy for “The Future Grid to Enable Sustainable Energy Systems,” an initiative of the Power Systems Engineering Research Center.

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The need for a smarter grid in the country has been mentioned in several literatures and has been advocated for by various government agencies and industries [1]. We present here features of today’s grid and the future smart grid.

A. Today’s Grid

Today’s grid is faced with the following challenges which include:

- Inefficiency: the overall efficiency of present day grid is about 40% ,
- Central generation domination– todays grid is designed to support mainly central generation making the integration of distributed energy resources difficult,
- Limited opportunities for consumers participation in the electricity market,
- Lack of anticipatory functionally – todays grid lack the ability to anticipate failure in power quality issues instead it focus is on protecting assets following fault,
- There is little integration of operational data with asset management – business process silos,
- They are vulnerable to malicious acts of terror and natural disasters because the topology of the assets.

These coupled with the aging infrastructure and workforce, stricter environmental and emission regulations/standards, increase in load demand and its complexity has necessitated the development of grid with intelligent capabilities i.e. Smart grid.

B. Smart Grid

A Smart grid is a self-healing grid with intelligence and communication capabilities. The following are some of the features of a smart grid:

- ability to delivers power in a wide area network,
- equipped with two way communication, automation tools, Renewable Energy Resources, smart measurement equipment, and fast decision support capability,
- greatly expanded data acquisition of grid parameters with a focus on prevention, minimizing impact to consumers,
- resilient to attack and natural disaster with rapid restoration capabilities,
- interoperability capability- the new grid must accommodate old central generators and distributed generation, storage for reserve margins, and create room for plug and play system such as PHEV
- real-time pricing functionality,

- robustness and ability to accommodate diverse source of energy, central generation and distributed generation such as Solar Photovoltaic, wind, Micro turbines etc.
- Power quality is a priority with a variety of quality/price options – rapid resolution of issues.

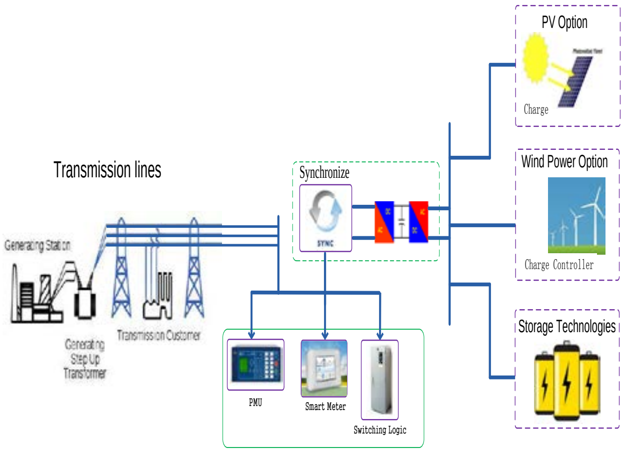

Fig. 1. Architecture of Smart Grid design

Although some designs and standards for smart grid exist, electrical engineering students are still less aware of the architecture and details of its functionalities [1]. Therefore it is important that current students who are the future workforce are equipped with adequate knowledge to develop competency in problem solving, design, analysis of technical challenges in the development of technologies for deployment of energy processing and smart grid network [4]. To this effect this course was developed and it aims to address the following topics:

- Fundamentals of Energy Systems,
- Tracking and Evaluation of the Renewable Energy Resources,
- Storage Techniques/ Options,
- Fundamentals of Smart Grid,
- Energy System Controls,
- Real Time Measurement for Smart Grid, and
- Communication, Protocol, Standards, Security, and Protection of Smart Grid

II. Devices Task Description

A new senior level course "Energy System for smart grid" which is also offered to 1st year graduate students was developed. To effectively communicate the contents of this course to the students, the course is taught via lectures (divided into 7 modules) and a laboratory section meant to provide the students with hands on experience of the course. A brief synopsis of each of the modules is done in this section.

A. Energy Processing and Smart Grid

1) Fundamentals of Energy Conversion Principles

Production of energy is usually in different forms and there is always a need to convert mechanical energy to electrical energy and vice versa. The machines utilized to achieve this are generators and motor respectively. They are made up of a moving part usually called the rotor and a stationary part is called the stator. Energy conversion in this machines results from conduction or induction interaction between the rotor and stator. The motion of the rotor part can be linear (such as linear motor or vibrating or reciprocating as in razor machine. Energy conversion also comes to play in induction machines [3]. These machines form a basis for development and processing of energy for central energy system for smart grid.

Central generation is still very important in the future grid due to its large power production capacity and the economics of size they provide. The advantage of central generation to smart grid power system is enormous because they guarantee more reliability and stability. Students must be exposed to the principles and concepts of current energy system thus the course on energy processing and smart grid provides initially the concepts of generators, motors and transformers. This material is based on basic circuits, electromagnetism and conversion technology. The over view of the materials covered include: electric machines with their equivalent circuitry modeling, application, testing procedures, performance analysis and limitation, standard requirements for sizing, interconnectivity of machines for existing and future grid, control measures for attaining stability of the machines through regular operation and maintenance (routine, corrective and condition based maintenance).

Students are usually taught that loads have constant impedance, current and power i.e. ZIP load however, practical power system are made up of different load types (frequency dependent load, voltage dependent loads and ZIP loads). These load types are modeled in the course and their impact on the systems voltage, frequency, reactive power and the active power generation is discussed. The students are assigned to conduct analysis with different load types using power flow packages such as NEPLAN and PSAT.

To ensure that students grasp the fundamentals of this concepts examples and hands-on calculation was provided to enable the students:

- Determine the terminal and phase voltage of both generators/motor machine under different load connection and power factor,
- Understand equivalent circuits in machine theory as used in open and short circuit test,
- Understand both machine (generator /motor) torque characteristic and speed relationship as well as role of governor, exciter and other central function,
- Understand Converters & Inverters (modeling and Characteristics).

2) Evaluation of Renewable Energy Resources

Continuous increase in load demand coupled with the increasing cost of providing energy to sustain current quality of life, new flexible energy sources that are affordable, sustainable, accessible and efficient are required. To avoid or reduce the need to build more central generators, new portable, sustainable standalone grid connected energy sources are required. This form the basis of micro grid which lends itself to smart grid when automation, communication and other features of smart grid are added [1].

Renewable Energy Resources [RER] can serves as source of electric and heat energy. Most renewable energy sources are green energy, which simply means, energy that is environmentally and socially sustainable. Today students and future workforce need to be accustomed with energy sources that are environmentally friendly and also understand the potential and limitations of RER. In light of these types of RERs (Photovoltaic, wind, hydro, biomass, and micro hydro), their advantages, and disadvantages, models for design and construction were discussed in this module. Also discussed is the concept of renewable energy penetration level in terms of

$$\frac{\text{Annual energy from RER in KWh}}{\text{Total Annual energy delivered to load kWh}} \tag{1}$$

To complete working knowledge of RER, issues of cost benefits, standard of interconnections, efficiency, reliability, safety, economics (cost benefit analysis) and security requirements were also discussed in this module.

3) Storage Techniques/ Options

Energy storage is of potential benefit to RER based power system because of the inconsistent nature of the power outputted. Storage systems also help transmission and distribution systems robustness due to its ability to serve as short time immediate power source to meet peak demand and bridge the energy gap required during generator startup. Storage devices are therefore very essential to the development of smart grid. The effort here is to study and compare various storage techniques such as high power batteries, super capacitors, pump hydro, hydrogen, high power flywheel etc. in terms of power rating, discharge and charging time, capacity, reliability, cost and environmental impact. To ensure the students grasp the contents of this module illustrative examples, problem solving, design and experimental work related to storage techniques, selection and sizing of different storage device were carried out.

4) Fundamentals of Smart Grid

Today's Electricity grid was designed to operate in a vertical structure consisting of generation, transmission and distribution system supported with controls and devices to maintain reliability, stability, and efficiency. Although today's grid currently supports energy demand, system operators are now facing new challenges that arise from the penetration of RER, rapid technology changes and the change in electricity market dynamics. This has necessitated smart grids equipped with communication support scheme, real time measurement capabilities and intelligence to enhance resiliency, sustainability, robustness, and security [1]. Current students who are the future workforce therefore need to be knowledgeable of the future grid design, its operation and control. The knowledge gained in this module is accessed by case-studies and design exercises.

5) Real Time Measurement for Smart Grid

Smart grid functionalities include efficient control of various components of the grid therefore; there is a need to properly monitor various operating parameters. To achieve real time measurement of the operating parameters such as voltage, angle and frequency of the system is required. New tools such as phase measurement units (PMU), supervisory control and data acquisition (SCADA), Energy Management System (EMS), Demand Side Management (DMS), Remote Terminal units (RTU), two-way digital communication are utilized to monitor, measure and analyze operating parameters of smart grid for efficient control, maintenance and optimization. This module provides an in-depth knowledge of the operating principles and application of PMUs, Smart meters, Intelligent Electronic Devices (IEDs), SCADA, RTU's, EMS, DMS. The use of the measured data acquired for stability (voltage and angle) and fault assessment is also emphasized. The students' knowledge of this module is tested through exams, simulation and case study analysis.

6) Energy System Controls

Energy consumers constantly desire to pay less hence, the future grid requires robust control functionalities. The future grid should not only be capable of controlling the electrical and mechanical system but should be capable of controlling the load as this will ensure reduction of power needs and associated costs. Data acquired using the tools discussed in previous section are utilized for real time control purposes. Smart grid should be equipped with real time control capability. This module addresses power system control devices, their functionalities and control techniques. Also discussed in this module is local and wide area control and state estimator. It is important that current students are equipped with the necessary skills required to design and operate the control scheme required for the future power system. In addition to a comprehensive study of this module the student are required to design and provide solution to case studies related to future grid and real time measurements.

7) Communication, Protocol, Standards, Security, and Protection of Smart Grid Devices

As energy enterprise is slowly restructured, utilities and customers are constantly demanding reduction in cost, improved efficiency and increase in operating flexibility. Smart grid power system attempts to ameliorate these needs through the introduction of communication options to support the distribution and transmission system such as power-line communication for electrical equipment's such as meters and switches [2]. Considering the sensitivity of the information's to be transferred between the customers and the utility the communication infrastructure has to be efficient and secured. Various standards, protocol and security options for information gathering and transfer between the customer and the utility will be discussed in this module. Exercise and case study analysis are used to access the student grasp of the techniques discussed in this section.

B. Laboratory Exercises

The course include laboratory exercises which are conducted using computer simulation packages such as NEPLAN and PSAT (MATLAB) and real time practical laboratory scaled power system devices.

- Measurement Techniques tools such as watt meters, Smart Meters Lab for power networks,
- Introduction to the power simulation tools such as NEPLAN and PSAT (MATLAB) and other power flow tools,
- Experiment on different renewable energy resources and different load types,
- Machine dynamics and control for AC, DC and induction machines and transformers, and
- Smart grid design experiment based on a micro grid features to be developed at Howard University.

1) Laboratory Example

Various experiments and simulations are currently being developed to provide the student with hands-on exercises on some of the principles discussed. An example of such exercise with the following objectives is discussed in this sub section:

- Understanding Electricity generation from renewable energy system,
- Investigation the integration of energy storage system into electricity network,
- Investigate the variability and stochasticity of renewable energy system such as Solar Photovoltaic (PV),
- Develop a system that combines AC and DC sources of energy,
- Practical study of a three bus system,
- Perform system studies such as power flow, optimum power flow, and fault studies etc. using setup shown in figure 2 below.

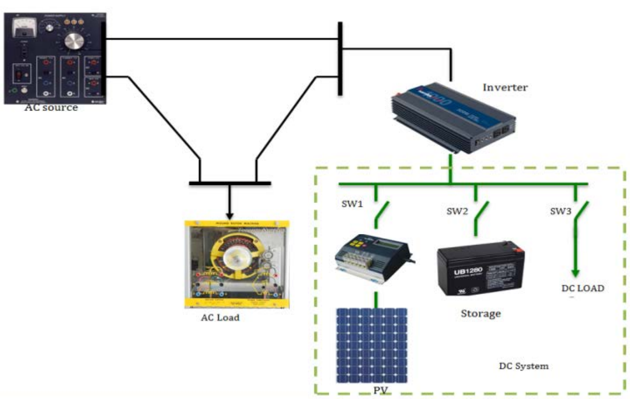

Fig. 2. Experimental layout for micro grid

a) Experiment 1

This experiment aims at the following based on the micro grid layout shown in figure 2:

- To investigate the characteristic of electricity generated from a renewable energy source (Photovoltaic (PV)),
- investigate inverter efficiency, and
- show the stochastic nature of some Renewable energy resources (RER).

Step 1: Connect the PV through the inverter to the load without the battery bank and AC source. Close switch 1(SW 1) and open switch (SW2) and (SW3) shown in figure 2.
Step 2: Measure the output current of the PV,
Step 3: Connect an AC load to the load bus.
Step 4: Take measurement of the current and voltage on the DC (colored in green) and the AC side i.e. immediately after the inverter and at the load at intervals of 30 minute.
Step 5: Plot the voltage vs. time and the current vs. time.
Step 6: Calculate the efficiency of the inverter.

b) Experiment 2

This experiment aims at following based on the micro grid layout shown in figure 2:

- to investigate the effect of Storage on the network performance,
- investigate the effect of storage system on the stochastic nature of some Renewable energy resources (RER), and
- show how storage system can compensate for the variability associated with RER.

Step 1: Connect the PV through the inverter to the load without the battery bank and AC source, i.e., Close switch 1 and 2 while 3 in figure 2 remains open.
Step 2: Connect a constant resistive load to the load bus.
Step 3: Take measurement of the current and voltage on the DC (colored in green) and the AC side i.e. immediately after the inverter and at the load at intervals of 30 minute
Step 4: Plot the voltage vs. time and the current vs. time.
Step 5: Vary the load and investigate the effect on the output current from the battery.

c) Experiment 3

This experiment aims at following based on the micro grid layout shown in figure 2:

- build a micro grid that is connected to the conventional power system,
- carry out load flow studies,
- carry out Loss studies,
- carry out sensitivity analysis,
- carry out fault studies,
- optimal load flow study, and
- stability studies.

Step 1: setup the power system as shown in figure 2,
Step 2: Vary the load and the reactance of the line and investigate the effect on power flow,
Step 3: Carry out a loss studies of the system resulting from variability of load and line reactance,
Step 4: disconnect some of the lines and investigate the effect on power flow and the loss on the system,
Step 5: Connect a constant load and measure the power flow on each of the lines,
Step 6: Replace the constant load with frequency dependent loads and investigate the power flow, the losses on the system,
Step7: replace the frequency dependent load with a voltage dependent load and repeat experiment 6,
Step 8: carry out stability analysis by introducing varying contingencies into the network,
Step 9: Suggest optimization strategies based on the result from step 6 and 7

C. Course Outline

The outline of the course developed is summarized in table I and II.

TABLE I
ENERGY PROCESSING FOR SMART GRID OUTLINE

Course I	
Title:	Energy Processing for Smart Grid
Class:	Electrical and Computer Engineering Seniors
Topic	Course Outline
Fundamentals of Energy conversion principles	• Three Phase Power, • Load Types, • Magnetic circuits, • Transformers, • Classical Machines, • AC/DC Machines, and • Converters & Inverters (Modeling and Characteristics)
Evaluation of Renewable Energy Resources	• Renewable energy resources including solar, wind, hydro, biomass, etc. • Modeling, and • Characteristics Evaluations in terms of: efficiency, reliability, cost, interconnectivity, etc.
Storage Techniques/ Options	• Energy storage characteristics, • Efficiency, • Cost, • Reliability, and • Environmental impact.
Fundamentals of Smart Grid	• Overview of Smart Grid concepts, fundamentals, and design, • Types of devices, • Advancements electricity grid, • Measurement tools, • Matrix of performance, • Security Issues, and • Communication requirements.
Energy System Controls	• Local & Wide area control, • Smart Grid performance Matrix(Voltage & frequency load control) • Real time control(Phase Measurement Unit-PMU), • State Estimations, and devices
Real Time Measurement for Smart Grid	• Concepts and Applications of Phasor Measurement Unit, Smart Meters, Instrumentals, Protection devices, and Intelligent Electronic Devices-IEDs, • Communications: Remote Terminal Unit-RTU, SCADA, Energy Management Systems-EMS, Distribution Management System-DMS, and • Advancements: Modern Substations, Distribution. Automation
Communication, Protocol, Standards, Security, and Protection of Smart Grid Devices	• Data Encryption and Decryption, • Protection, • Computation Analysis, • Communication controls, and • Security Options
Laboratory exercise (applicable to both the fundamentals of energy systems and energy processing for smart grid course.	• Understanding Electricity generation from renewable energy system, • Investigation the integration of energy storage system into electricity network, • Investigate the variability and stochasticity of renewable energy system such as Solar Photovoltaic (PV), • Develop a system that combines AC and DC sources of energy, • Practical study of a three bus system, and • Perform system studies such as power flow, optimum power flow, and fault studies

TABLE II
FUNDAMENTALS OF ENERGY SYSTEM COURSE OUTLINE

Course II	
Title:	Fundamentals of Energy System
Class:	Electrical and Computer Engineering Juniors
• Introduction to Power Systems, single phase and three phase circuit analysis, • Understand magnetic circuit analysis, magnetic properties of materials, transformer theory and applications, • Review basic primary energy sources and applications to central power generation, • Understand the fundamentals and applications of solar and wind energy technologies, • Introduction to Power Electronics Converters (Inverters and Converters), • Understand the principles of operation and design of three phase AC machines, • Understand the principles of operation and design of induction and DC Machines, • Review of Smart Grid Fundamentals, • Understand the fundamentals of Transmission model and power flow analysis, • Understand the Use of PSAT and MATLAB in energy conversion performance analysis and power flow computation.	

III. RESULTS

Students now appreciate current trends in the provision of energy, especially as related to the integration of renewable energy and storage facilities into the power network.

Students have also come to appreciate the interdisciplinary component of the development of the future energy system.

Finally, students more appreciate the knowledge gained from previous classes in electronics, networks, signals and system that they have taken because they are able to see the direct application of that knowledge to power network development.

IV. CONCLUSIONS

The course Energy processing and smart grid is a senior level course which is also offered to 1st year graduate students without previous power system background. This course provides foundation of energy conversion and processing from classical machines through renewable energy options. Storage energy techniques and the benefits were introduced. To address the fundamental of smart grid, different measurements techniques used in the development of smart grid are included e.g., PMU, smart meters. Furthermore different control strategies such as voltage frequency control, VAr control, etc. for local and area wise control is defined. The capability of smart grid to achieve a sustainable, secure, efficient grid of the future is fundamental to the course. To interest junior ECE students a portion of the course has been approved by the Howard university ECE department to replace the existing junior ECE required energy conversion course.

The course contents have been analyzed and summarized in Tables 1 and 2. To facilitate hands-on experience, laboratory set up for testing energy conversion components, storage options, measurement technology, controls and smart grid technology and systems. These courses are being taught during the spring 2013 simultaneously. The response to the course material continues to be outstanding. The lecture materials are being validated through student's feedbacks/ commitments to ensure its value to other PSERC schools in the future. The course materials will be compiled into an e-book format when fully developed and made available to the other PSERC schools.

V. Future Work

Two courses "Fundamentals of energy system" and "Energy processing for Smart Grid" have been developed from the PSERC Future Grid Initiative grant for juniors and seniors/1st year students respectively.

During the coming summer we plan to do the following:

- provide integrated problem solving and laboratory exercise covering the topics discussed in different modules,
- we plan assemble the lecture materials as a text book and make it available online,
- we plan to use the material developed to initiates projects in our pre-college for engineering systems program, senior projects, and graduate research.
- we plan develop IEEE papers for wider dissemination, and
- we intend to develop new research and education topics in areas of application of smart grid for customer appliances.

VI. Access to Products

Lecture notes will be collated into a book that will be published and available for purchase from bookstores.

An online e-book version will also be available when the course materials are fully developed and posted on the Center for Energy System and Control website: http://cesac.howard.edu/.

Further detail of the course can be requested from the author via email

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VIII. Biographies

James Momoh received the B.S.E.E. degree from Howard University in 1975, the M.S.E.E. degree from Carnegie Mellon University in 1976, the M.S. in systems engineering from the University of Pennsylvania in 1980 and the PhD in Electrical Engineering from Howard University in 1983. His current research activities are concentrated in stability analysis, system security and expert systems design for utility firms and government agencies. Dr. James Momoh is the former Department Chair and current professor of Electrical and Computer Engineering at Howard University, Director of the Center for Energy Systems and Control (CESAC), and former Director of ECE department at NSF. His research area is focused on optimization applications, power flow, distribution automation, computational intelligence applications, and smart grid. He is also the author of several papers and books including a best-seller, 2nd edition of Electrical Power System Applications of optimization by CRC Press and Smart Grid: fundamentals of Design and Analysis. Finally, he is a Fellow of IEEE.

Energy Economics and Policy: Courses and Training (4.5)

James Bushnell, *University of California, Davis*
Severin Borenstein, *University of California, Berkeley*

***Abstract*—An understanding of the economics of energy markets is necessary for framing reasonable expectations about the likely adoption and usage of any future technologies that will be applied to the nation's electricity grid. In all industries, there are many examples of technologies that have not advanced beyond the University or laboratory research stage. The energy industries feature several economic aspects that further complicate the commercial transformation and adoption of new technologies. This project has developed a series of courses designed to develop a richer understanding of the economic issues confronting businesses, regulators, and researchers in the energy industries.**

I. Introduction

The Electricity Industry is confronting significant challenges and opportunities that require the coordination of both technology and economic policy development. While much of the existing electric infrastructure is aging beyond its originally designed lifespan, both the utilization of that infrastructure as well as the constraints within which services are delivered are rapidly changing. Potentially large scale application of electricity to the transportation sector may substantially transform both the timing and location of electricity use. At the same time, environmental challenges with respect to both climate and local pollutants are motivating significant changes on the supply side, such as a major increase in the role of intermittent renewable generation sources.

It has been widely expressed that new technologies, particularly the suite of technologies that have come to shelter under the semantic "smart grid" umbrella, are necessary to meet the challenges presented by these transformative changes. However, the development of new technologies, while likely necessary, is not sufficient for their successful application to the power industry.

In all industries, there are many examples of technologies that have not advanced beyond the university or laboratory research stage. Beyond this, the energy industries feature several economic aspects that further complicate the commercial transformation and adoption of new technologies. For example, the prominent role of economic (e.g. rate-of-return) regulation is probably the most significant element distinguishing this industry from most others.

Therefore, any analysis of the future trajectory of the role of the future grid must begin with a clear picture of the current and future costs and capabilities of the *existing* grid. Historically within the US, the technical capability of the nation's transmission network has been far more sophisticated than the market institutions put in place to utilize that infrastructure. Over the last 15 years, the advent of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) has revolutionized the way in which users of the grid interact with each other at the wholesale level. In some places, this has lead to a substantial leap in the utilization of network services, *in the absence of any technological changes to the physical infrastructure.*

However, within the US electricity industry there are still many areas where market design, regulatory policy, and incentives still lag behind technology. About half the country still lacks transparent, formal markets for "balancing" the supply and demand of power in real-time. Many of these regions, particularly in the west outside of California, also contain vast potential for renewable energy development. However, without modern techniques for marketing energy and clearing markets with intermittent supply, the economic development of these resources will be constrained.

Economic policies for utilization of the future grid at the retail level are also relatively primitive compared to those being applied at the wholesale level in some regions. Despite the increasing adoption of "smart-meters" for many retail customers, the structure (but not the level) of retail rates for the vast majority of those customers remains unchanged from those applied 30 years ago when meter technology limited pricing options.

In short, unless advances in the economic and market design realms keep pace with those in the technology realm, the full potential smart grid technologies will not come close to being realized.

II. Task Description

The energy economics task within this track has focused on coursework that can be applied at a variety of technical levels to a broad set of prospective students. University coursework has been developed for the masters level as well as doctoral level. In addition, some material has been adapted to a "short-course" format for industry professionals.

The work described in this paper was made possible by funding provided by the U.S. Department of Energy for "The Future Grid to Enable Sustainable Energy Systems," an initiative of the Power Systems Engineering Research Center.

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The courses cover the economic fundamentals of both electricity and energy markets. The goal is to provide a deep understanding into the economic and technological drivers that led to the regulatory policies and market institutions that have dominated the electricity industry over the last century. From such a base, one can explore how advances in both technology and economic policy have made possible new market designs and helped to spur increased wholesale trade.

A complete view of the potential role of the future grid within the energy sector must also consider the economic characteristics that permeate the energy industries. The energy industries are heavily influenced by environmental and network externalities, as well as the long-term physical constraints of exhaustible resources. There is also the potential for (and reality of) significant market power in many segments, caused by the relatively concentrated control of both physical resources and intellectual property. While essentially commodities, energy markets are also frequently separated by the costs and limitations of storage and transportation. The presence of all these influences contributes to the large role of government regulation and policy in the energy sector.

Because of all these factors, the behavior of individuals and market segments frequently deviates from the path predicted by technical models whose focus is on minimizing costs. A better understanding of the interplay of these factors is needed to accurately assess the impacts that specific public policies, such as tax-credits, purchasing mandates, and loan-guarantees, can have on market outcomes. The techniques of empirical economics, with their careful consideration of such issues as identification, endogeneity, and data quality, provide invaluable tools for measuring the magnitude and implications of the economic factors usually absent from purely techno-economic, cost-based assessments of new technologies.

III. Course Design

The energy economics courses and training can be applied at a variety of technical levels to a broad set of prospective students. University coursework has been developed and delivered at masters level as well as doctoral level. In addition, some of the material has being adapted to a "short-course" format for industry professionals.

The courses cover the economic fundamentals of both electricity and energy markets. The goal is to provide a deep understanding into the economic and technological drivers that led to the regulatory policies and market institutions that have dominated the electricity industry over the last century.

A. Doctoral Level Course Material

Table 1 presents a high level list of topics covered in ECON 221 A at UC Davis.

TABLE I
TOPICS FOR PH.D. COURSE

- I. Regulation and Regulatory Reform
  - a. Regulation of Natural Monopoly
  - b. Regulation, Pricing and Consumption
  - c. Regulation of Competitive Markets
  - d. Deregulation of Energy Markets
- II. Auctions and Energy Markets
- III. Horizontal Market Power
  - a. Static Models of Oligopoly
  - b. Empirical Analysis of Competition
  - c. Forward Commitments and Competition
- IV. Vertical Integration
- V. Dynamic Models of Competition
- VI. Environmental Regulation and Industrial Organization

The course work was built around an exploration of the economic concepts followed by a close review of specific research papers dealing with each topic. This is the typical approach in graduate courses in the social sciences. The research papers covered in the course are summarized in the references to this report.

Two areas of the Ph.D. course that received strong emphasis are topics relating to economic regulation and those relating to competition in deregulated markets. Because they are broadly viewed as filling a natural monopoly function, pricing in almost all electricity networks remains largely driven by the principles of cost-of-service regulation. For nearly fifty years, economic research has debated the efficiency, and inefficiencies behind both the theory and practice of natural monopoly regulation.

Regulation has produced inefficiencies in production, through a distortion of incentives away from cost minimization. The practice of electricity rate design, with its focus on the recovery of average costs, rather than providing a signal of marginal cost, has also contributed to inefficiencies in consumption. One alternative is the deployment of time-varying retail prices, such as real-time pricing. One objection to time-varying retail prices is the perception that it would price increase volatility and risk faced by consumers. The course covers papers that study the magnitude of these risks and methods by which such concerns can be mitigated.

Another area to receive extensive, multi-lecture treatment is the study of market-power and competition policy. While it has been sometimes asserted that competition in electricity markets is fundamentally different than that in other industries, much recent research shows that outcomes in electricity markets can be understood within the context of long-established paradigms for competition once one accounts for the extreme attributes of power markets. These include the extreme inelasticity of demand and the high cost of storage.

The lack of economic storage also raises the importance of pricing of transmission usage, because congestion plays such a prominent role. The principles of congestion pricing are therefore central to the efficient operation of power networks. The potential for transmission congestion also greatly complicates the nature of competition between unregulated producers. Figure 1 Illustrates how even a relatively simple model of Cournot best-response functions between two identical firms becomes complex in the presence of potentially binding transmission constraints.

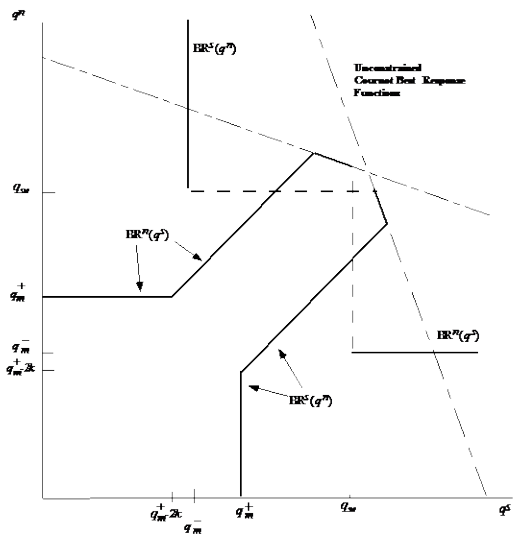

Fig. 1. A slide showing the Cournot best response functions of two firms in a congestion transmission network

B. Masters Level Course Material

The Master's level course was organized around specific economic concepts and topics, with some case studies of market events. Table 2 summarizes the topic list for MBA 212 in the Spring of 2012.

TABLE II
TOPICS IN MASTERS LEVEL COURSE

1. Pricing, Scarcity, and Market Efficiency
2. Market Power in Energy Markets
3. Case Study: The California Electricity Crisis
4. Natural Resource Extraction and Pricing
5. The Economic Role of Storage
6. The Economic Role of Energy Transport
7. Commodity and Futures Markets
8. Regulation of Natural Monopoly
9. Deregulation of Non-Monopoly Markets
10. Competition Policy and Antitrust
11. Vertical Structures and Business Models
12. Environmental Regulation and Externalities
13. Energy Efficiency
14. Alternative Energy Policies

Unlike the Ph.D. course, which is directed at professionals who will be performing advanced analysis and research on energy markets, the masters level course emphasizes the basic economic fundamentals that most strongly influence outcomes in energy markets. The level of the material is much less technical, in a mathematical sense, although there is much overlap in the economic concepts that are discussed.

IV. RESULTS

Within this task, three levels of courses have been deliverd over the past 2 years. These are summarized in Table III. In Spring 2012, 62 students enrolled in MBA 212 at the Haas School at UC Berkeley. The class included students from the Haas School, Engineering, and the Energy and Resources Group at UC Berkeley. The class was very popular and student reviews rated it at a 6.8 on a 7 point scale.

TABLE III
COURSES AND SOFTWARE DELIVERED

1. A Masters level course delivered at the Haas School of Business during Spring 2012 and Spring 2013.
2. A Ph.D level course delivered in the Economics Department at UC Davis during fall of 2012.
3. Professional- level short-courses delivered in Davis, CA during 2012 and Oakland, CA during 2013.

In fall of 2012, 8 Ph.D. students and two auditors enrolled in Econ 221 A at UC Davis. Students were from Economics, Agricultural and Resource Economics, Electrical Engineering, and the Transportation Technology and Policy Group. One auditor is now working for the Department of Market Monitoring at the California ISO.

In the Summer of 2012, a two-day short course was held in Davis, CA. These course feature subsets of the longer semester long courses described above. The focus of each short course is targeted to the audience. Enrollment was 64 and included staff from the California Air Resources Board, California PUC, several utilities, and several renewable energy companies. In Spring of 2013, another two-day course was held in Oakland CA. Attendance was dominated by staff of the CPUC, but also included representatives of utilities and independent power developers.

C. Electricity Strategy Game

Another component of the project has been the refinement of a game-based learning tool called the *electricity strategy game* (ESG). The ESG is a team-based game where teams of students value, purchase, and deploy portfolios of electricity generation plants in a simulated deregulated electricity market. The game has been adapted and run in courses at several universities, including Stanford, Yale, MIT, Dartmouth, and Michigan.

The electricity strategy game is primarily an intellectual exercise designed to familiarize students with the concepts and principles of daily electricity auction markets. Portfolios of five to ten generation units of varying costs and capacities are bid into a central auction market. The software, designed to run on Stata, tabulates market outcomes and the financial positions of each team for each round.

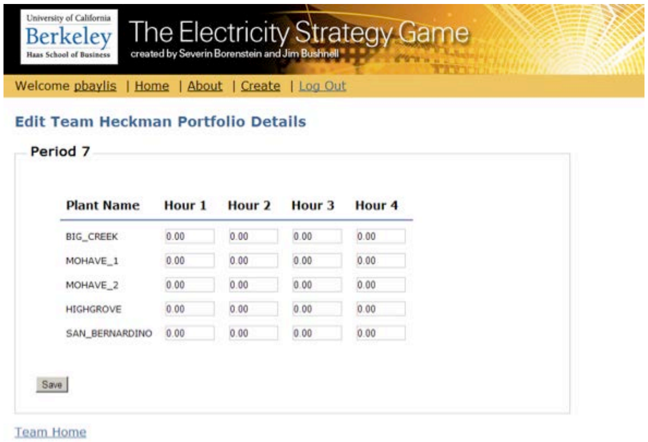

Fig. 2. A Screen Shot of a Bid Submission Page from the ESG

The game is designed to be flexible so that instructors can add aspects to the market that they wish to emphasize. Additional aspects might include forward markets, transmission constraints, and emissions markets.

V. Access to Products

Two sets of materials are available upon request from instructors at accredited non-profit universities. One set includes the instructional materials for the classes (syllabi, slides). The other set of materials provides instructions and links for running the electricity strategy game. These materials are currently hosted on the website. The website hosting these materials is http://www.ucei.berkeley.edu/energycourse.html. These materials are password protected and can be made available upon request.

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VII. Biographies

Severin Borenstein is the E.T. Grether Professor of Business Administration and Public Policy at the Haas School of Business and Co-Director of the Energy Institute at Haas. He is also Director of the University of California Energy Institute. He received his A.B. from U.C. Berkeley and Ph.D. in Economics from M.I.T. He has published extensively on the airline industry, the oil and gasoline industries, and electricity markets.

James Bushnell is an Associate Professor in the Department of Economics at the University of California, Davis. Prior to joining U.C. Davis, he spent 15 years as the Research Director of the University of California Energy Institute, and two years as the Cargill Chair in Energy Economics at Iowa State University. Bushnell received a Ph.D. in Operations Research from U.C. Berkeley. He has written and consulted extensively on the regulation, organization, and competitiveness of energy markets.

PSERC Academy: A Virtual Library of Thousands of Short Videos (4.2)

Raja Ayyanar and Siddharth Kulasekaran
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***Abstract*—This project aims to take advantage of the advances in e-learning technologies to provide workforce training in the area of power engineering, power electronics and sustainable energy systems. An online library of a large number of short videos, with supporting user-interactive material including simulations, animations and quizzes with instant feedback are being developed. The videos and other training material can be used as a complete self-learning e-resource, as a complement to class lectures, or as a reference material for practicing engineers. As part of the Future Grid Initiative, three modules on basic power electronics, photovoltaic power conversion and wind energy are under development and will be made available publicly through a dedicated website. Support from federal agencies and industry will be sought to sustain the academy beyond this initiative and to develop modules on other aspects of sustainable energy systems through a collaboration of a large number of PSERC faculty and industry members.**

I. Introduction

The evolution of the future grid is fast-paced and the key technologies are in constant flux. The curriculum and training to develop the workforce that will design and operate the future grid, therefore, also needs to be fast-paced, flexible and able to quickly adapt to rapid technology developments, while simultaneously ensuring solid foundation in the fundamentals of core power engineering disciplines. Barring a few major power programs, in many of the universities, specialized power courses cannot be offered due to low student enrollment or lack of instructors or facilities. In the few courses that are offered it is always a struggle between the breadth and the depth of coverage. The pace and rigor of the course also typically need to be geared towards the average student.

Advances in e-learning technologies, and ubiquitous access to high speed internet provide a tremendous opportunity to address the above challenges. The task 4.2 aims to take advantage of this opportunity for workforce training in the broad area of sustainable energy systems. Specifically, the main objective of this task is to develop an online library of short, i.e., 15-20 minute videos on various topics of sustainable energy systems, smart grid and power engineering, and on important background topics required to understand these concepts, and make them available to anyone motivated to learn power engineering concepts or in need of a quick reference on a new topic.

The vision is to develop, over a period of many years, several hundreds or even thousands of such online videos covering a wide spectrum ranging from basic introductory material to advanced topics, delivered using a range of methods from simple lectures and derivations of equations to sophisticated multi-media delivery. While the other tasks in the workforce development thrust area develop well-defined courses based on the identified gaps in existing curriculum and projected requirements, the PSERC Academy by design is more flexible and adaptive, both in terms of contents and format. It is by design meant to evolve over time based on user and expert feedback, changing needs and changing learning technologies.

The online library complements conventional curriculum as well as addresses the needs of practicing engineers. Flexibility by design, ability to adapt based on continuous feedback, and self-paced learning for individual students are some of the major advantages of this online resource. As the library grows in volume and with the collective resources of PSERC, most of the advanced and specialized topics in sustainably energy systems can be covered in depth. In addition, cutting-edge research can also be quickly made accessible to practicing engineers and researchers.

It should be emphasized that the objective of PSERC Academy is NOT to just provide superficial overview of various topics because of the short duration of each video. It is just the opposite – with thousands of videos, the objective is to provide as much details and analytical rigor as needed, and in as many different topics as is relevant, in order to gain a thorough understanding of a particular field and the ability to use them in practical applications. For example, the topic of photovoltaic inverters will have an 'overview' video that provides an overview of the functions of a PV inverter. But it will also include about thirty (30) or more videos that go into the detailed design of PV inverters including various converter topologies, control methods, PV models, MPPT algorithms, standards, anti-islanding methods, microgrid operation, and several design examples and simulation validation. These videos together with several more delivered as part of basic power electronics module will give a student or a practicing engineer enough information to help in the actual design of PV inverters. In addition, there will be several more videos on modeling of PV inverters in power system

The work described in this paper was made possible in part by funding provided by the U.S. Department of Energy for "The Future Grid to Enable Sustainable Energy Systems," an initiative of the Power Systems Engineering Research Center.

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analysis tools that will help power systems engineers to directly apply these in their system level studies without going through the details of inverter design. Over several years, through continuous additions based on emerging needs, it is possible that the topic of PV inverter alone may have more than a hundred videos.

The idea for PSERC Academy is partly inspired by the success and impact of *Khan Academy*, a not-for-profit initiative, whose 4000+ video library on basic math, science and other topics is one of the most-used educational video resources as measured by YouTube views per day and unique users per month [1]. The PSERC Academy targets a more advanced level of audience such as undergraduate and graduate students and practicing engineers and the format needs to be significantly different, but the vision is to make an equally powerful impact in the area of sustainable energy systems. It could serve as a quick reference material much like Wikipedia (but content prepared by recognized experts in the respective areas), or a complete curriculum that instructors can adapt, or as a complete self-learning e-resource. An interesting application for the videos will be to use these as the complete lecture component of a class, and use the freed-up class time for a series of highly productive instructor meetings with small groups of students.

II. Task Description

A. Video Creation Using Screencast Method

After comparing various possible approaches, the videos are being developed using *screencast* method, since the videos will have a combination of power point slides, use of analytical tools such as MathCAD and MATLAB, extensive simulations, derivations of equations by hand (with power point slides in the background) and animations. A screencast is a method to digitally record the computer screen output combined with audio narration in the background. After evaluating different *screencast* tools, Adobe Captivate has been chosen for this application. Figure 1 shows a screen shot of video development using Adobe Captivate.

Several videos for the two modules on power electronics and photovoltaic power conversion have been created. The topics covered so far in the power electronics module include:

- Introduction to power electronics
- Basic principles of switch-mode power conversion
- Steady state analysis and cycle-by-cycle averaging
- Extensive analysis and design of non-isolated converters including buck, boost and buck-boost
- Basic principles of isolated power converters and transformer principles
- Extensive analysis of a few isolated topologies such as isolated boost DC-DC converter
- Principles of voltage source converters in DC-AC applications
- Concept of power pole as a building block of all power converters
- Extensive analysis of single-pole, two-pole and three pole converters
- Simulation of different converter topologies

The topics covered so far in the photovoltaic power conversion module include:

- Operation of a basic PV cell and concepts of charge separation and photovoltaic effect
- Circuit model of PV cells and simulations
- I-V and P-V characteristics of PV cells and modules and impact of various parameters on these characteristics
- Extraction of parameters needed for PV modeling from datasheet and validation through matching of I-V curves

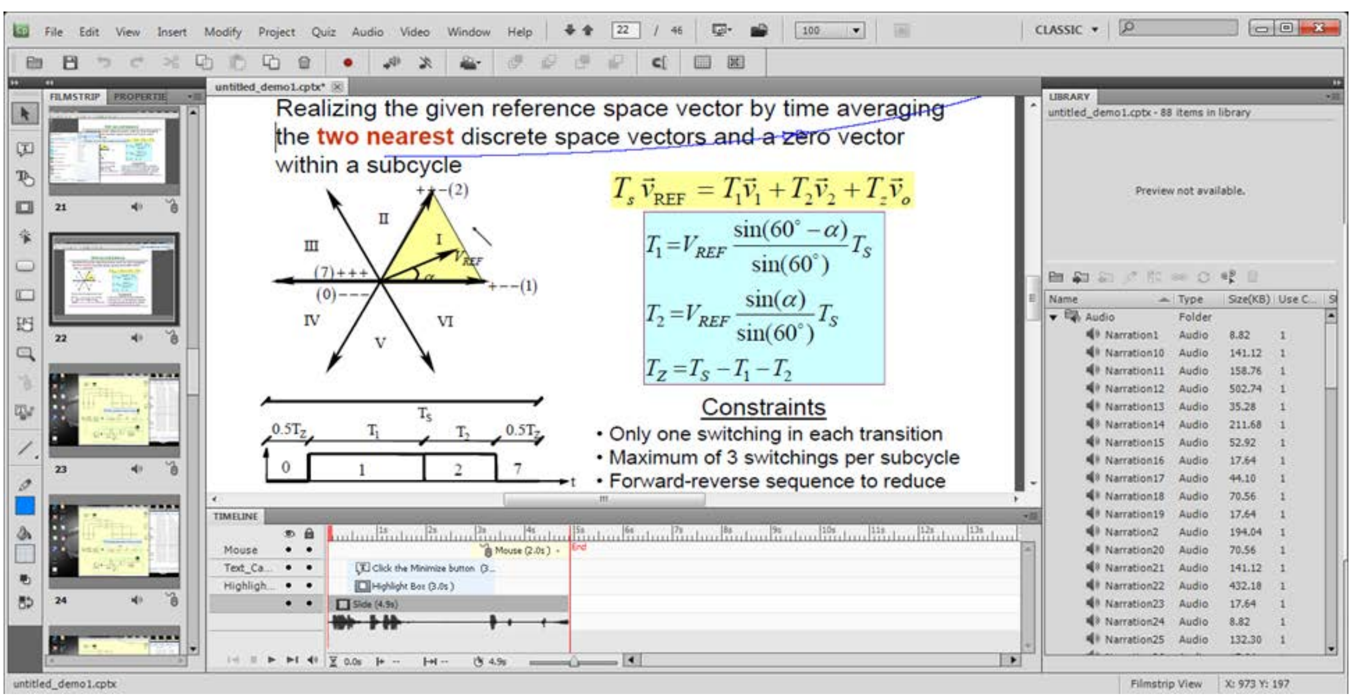

Fig. 1. Screenshot of video handling in Adobe Captivate

- Series/parallel connection of PV cells to form modules, strings and arrays and the corresponding equivalent models
- PV system configurations for different applications
- Typical specifications and components of a commercial string inverter
- Design of DC-DC converters for PV power conversion
- Two pole converters for single phase grid integration of residential PV
- Phasor analysis for different operating modes of string inverters

Additionally, materials for other topics in power electronics and PV as well as in wind energy conversion have been developed for creating videos on these topics in the near future.

The videos developed through Captivate have significantly large sizes, typically above 60 MB each for a 15-minute video in high definition. After considering a few possible solutions, it has been decided to use YouTube for hosting the videos and provide links to the videos and host other learning material in a dedicated website for PSERC Academy. The videos uploaded so far are 'unlisted' which means that they are not yet public but those who are given the correct URL can view them. A sample video from the power electronics module and another sample video from PV module can be viewed at http://youtu.be/kUbvY0Z0dfM and http://youtu.be/vuZR0X-YzFo respectively. Screenshots of some of the videos uploaded to YouTube are shown in Fig. 2.

B. Extensive Simulation in Videos and Stand-Alone Exercises

Extensive simulations using industry standard simulation tools have been developed as part of the educational initiative to reinforce the concepts learnt as well for use as design tools. Several power electronic simulators were compared for use in the videos, and finally a popular simulation tool namely PLECS has been chosen for the power electronic component of the academy due to its speed, simplicity of use, and features to interact with MATLAB/Simulink. Many of the developed videos demonstrate advanced concepts or verify design using PLECS simulations. Many of the simulation files will be made available to the users as demo models. We are working with Plexim [2], developers of the PLECS tools to provide limited license to users to run the demo models and offer limited flexibility to change parameters and configuration to these files. Many of the videos developed so far on power electronics and PV power conversion have corresponding simulation validation and illustrations. As an example, a PLECS schematic corresponding to a PV panel with a number of PV cells in series is shown Fig. 3. This simulation can be used to study the effect of different cell parameters such as diode characteristics and parasitic resistances as well as the effect of different environmental conditions such as insolation and temperature on the PV characteristics. It can also be used to validate the methods described for extracting model parameters from datasheet. For example, simulation output (I-V and P-V characteristics corresponding to a commercial PV

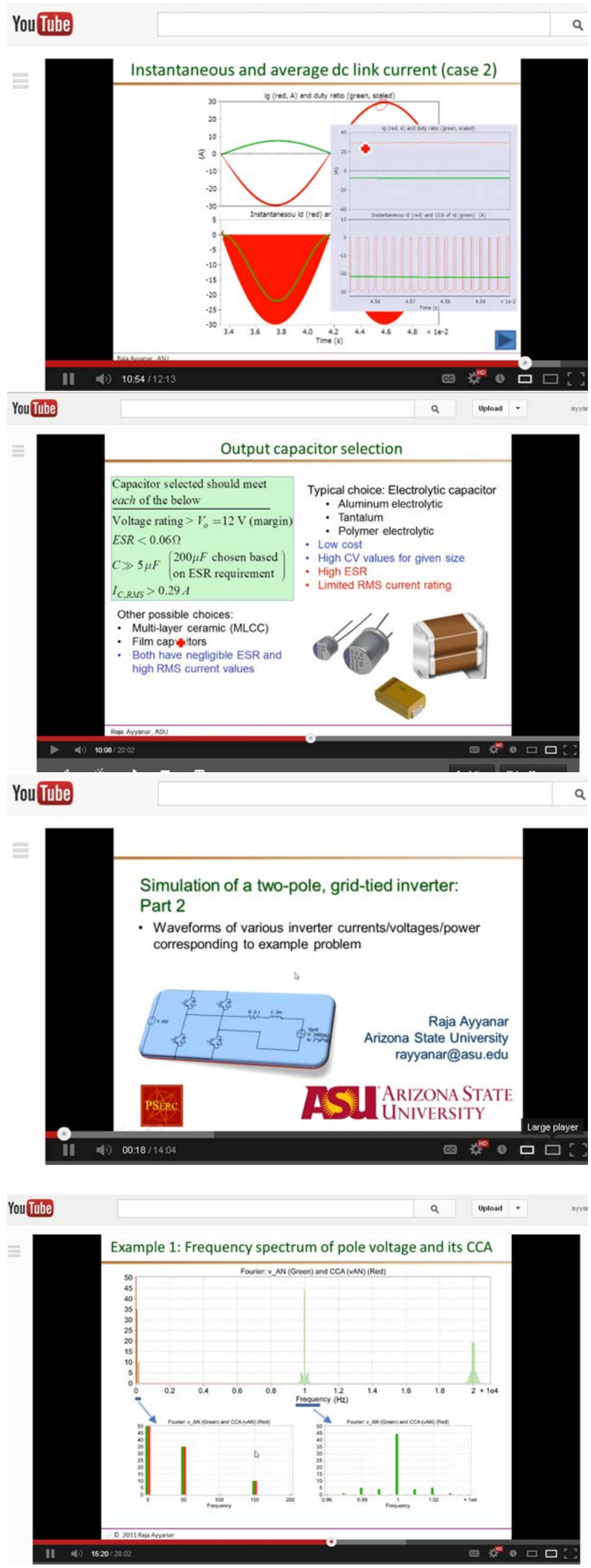

Fig. 2. Screenshots from four sample videos

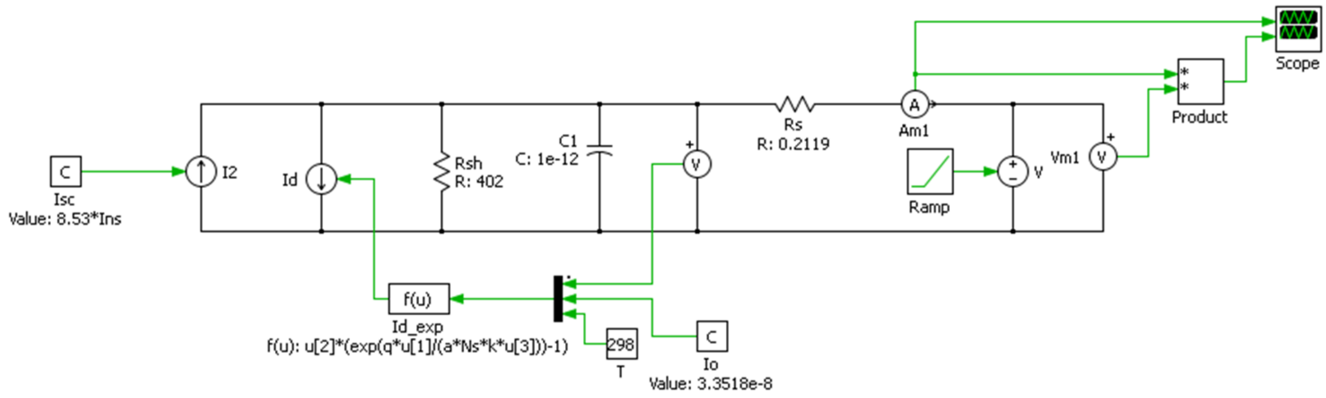

Fig. 3. PLECS schematic of a commercial PV module

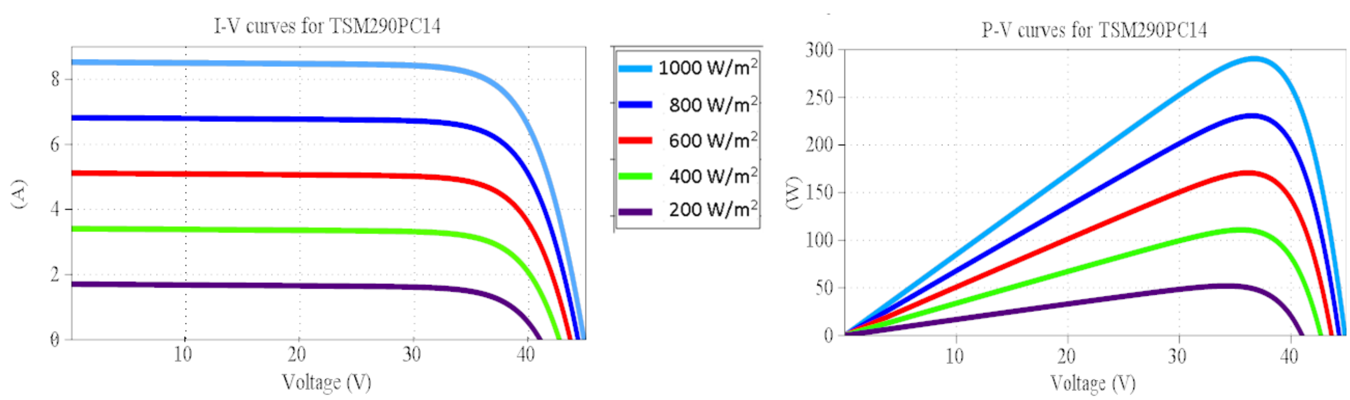

Fig. 4. Simulated I-V and P-V curves for module of Fig. 3

module) corresponding to change in insolation levels are shown in Fig. 4. These can be readily compared with the I-V curves provided in datasheets to validate the methods discussed in the videos.

C. User Interactive Animations and Quizzes

Highly user-interactive animation modules that reinforce the concepts covered in videos have been developed using JavaScript and tools available in MathCAD and MATLAB. For example some of the animations created help the users to vary the PV cell parameters, insolation or temperature and observe their impact on the I-V and P-V characteristics of the PV cells instantaneously. Similarly, the animations on several non-isolated and isolated converters allow the users to vary the input and output voltages, duty ratio, switching frequency and load, and allow them to observe the impact on the various converter voltages and currents and performance measures such as high frequency ripple and system losses. Some of the videos use these animations for explaining concepts while several other animations will be only for the users to experiment with. As an example, Fig. 5 shows the animation created to interactively learn about the operation of a simple step-down DC-DC converter.

Specially designed, user interactive quizzes have also been developed using Adobe Captivate corresponding to several of the topics covered in videos. These quizzes give instant feedback to the users on the grasp of material, explain potential source of user errors, and suggest additional help where needed. Many of the quizzes are multiple choice questions which require the user to analyze circuit schematics of power converters, waveforms at critical nodes or design parameters to solve these questions.

III. Results

The videos created so far have not yet been made public, and the uploaded YouTube videos are still unlisted. However, some of the relevant videos (YouTube links) for the ASU course EEE472 – Power Electronics and Power Management were uploaded to the course website (Blackboard) in Fall 2012. The class had an enrollment of 80 students with a mix of undergraduate and graduate students. The student interest and response have been very encouraging. Within two months in this semester the videos had been accessed more than 1200 times by the course students and we have been able to obtain positive and useful, feedback on the videos. Suggestions related to the content, speed of delivery, length of videos, and type of simulation exercises have been considered in the creation of later videos. In addition, feedback received from faculty and industry members of PSERC during industry advisory meetings have been encouraging.

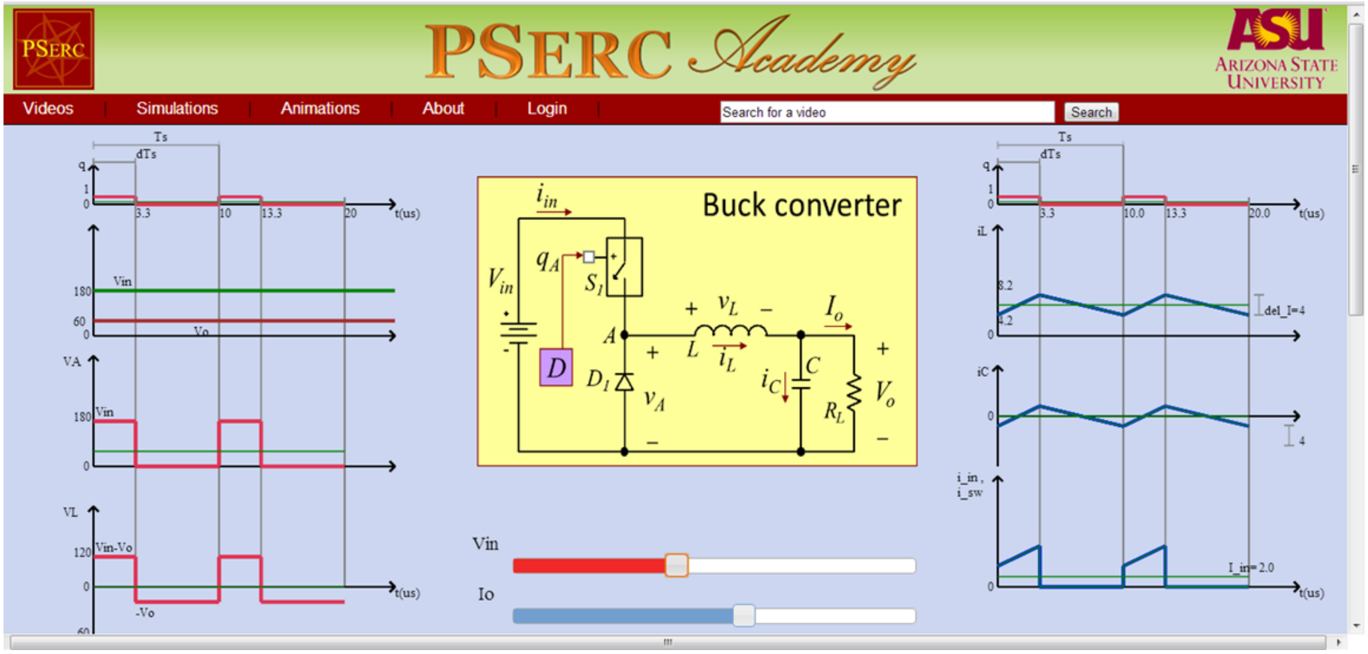

Fig. 5. Screenshot of an interactive buck converter animation

IV. Conclusions

Freely available online library of well-designed educational videos has a significant role in the workforce training related to sustainable energy systems. Depth and breadth of coverage on various topic areas need not be compromised and users can learn at a pace most suitable for them. The short duration of around 10-15 minutes seems to be optimal in terms of retaining student interest and focus while simultaneously being able to cover a meaningful amount of material in a given video. Hands-on simulations and interactive animations are some of the best ways to learn and retain new concepts in this area especially in power electronics.

The creation of a large number of videos proved to be an enormously time consuming endeavor. Considering all the steps involved - identifying concepts to cover in a 15 minute video, preparing illustrations, visual aids and power point slides, creating simulations and animations, recording in Captivate in various modes, checking for errors and fine tuning, processing the videos for format suitable for YouTube and eventually uploading to YouTube and updating the website, it can easily take upwards of five (5) hours for a single 15-minute video.

V. Future Work

Several more videos on power electronics and PV power conversion modules, and the complete module on wind energy systems will be completed before the end of the project on Future Grid Imitative. Upon completion of the critical set of videos on the first two modules, the website and the YouTube videos and all of the simulation files will be made public.

In order to sustain the PSERC Academy beyond the Future Grid Initiative and to develop videos and educational material in other areas of power engineering and sustainable energy systems, significant funding is needed. Plans to prepare proposals for the same are being pursued. Active collaboration of PSERC faculty and industry members in this endeavor will be sought.

In addition to educational and training videos, another potential application for PSERC Academy significantly enhancing its value will be to disseminate current research through short videos on the research developments and results. The author has been including PSERC Academy as a potential venue for disseminating research results in recent research proposals to NSF and DOE.

VI. Access to Products

A dedicated website for PSERC Academy is under development and when completed it will be hosted by the Arizona State University. Approval for the domain name PsercAcademy.asu.edu has already been obtained. The website will have search and interactive features and will contain links to all the videos (posted to YouTube), lecture material, simulations, animations and quizzes in logical modules. Communication among the users will be encouraged through forum for comments, questions and discussions. The website will be freely available to the public and registration (also free) will only be required for those who want to take part in online discussions. The terms and conditions of use of the videos and other products developed by the author are still under development and are likely to be those followed by similar online educational initiatives. The terms and licensing for the use of PLECS simulation files will be developed in consultation with PLECS developers namely Plexim. A screen shot of the home page of the PSERC Academy website partially showing modules on power electronics and PV power conversion. The pdf version of the power point slides handouts (6 or 9 to a page) are also included such that the user can quickly get an idea of the specific topics that a given video covers. As seen, many of the videos also have associated simulation, animation and/or quizzes.

Fig. 6. A screenshot of the PSERC Academy home page

VII. Acknowledgment

The authors gratefully acknowledge the contributions of Sindhuja Sadayandi in designing and developing the PSERC Academy website and help with Java script for the initial animations. Chenhao Nan also contributed in making some of the animations.

VIII. References

[1] www.khanacademy.org
[2] www.plexim.com

IX. Biography

Raja Ayyanar received an M.S. degree from the Indian Institute of Science, Bangalore and a Ph.D. degree from the University of Minnesota, Minneapolis. He is an associate professor in the School of Electrical, Computer and Energy Engineering at the Arizona State University, Tempe, AZ. His research interests are in the areas of power electronics and renewable energy resources.

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Smart Grid Education for Students and Professionals (4.3)

Mladen Kezunovic, *Texas A&M University*; Sakis Meliopoulos, *Georgia Institute of Technology*; Mani Venkatasubramanian, *Washington State University;* Vijay Vittal, *Arizona State University*

***Abstract*— This effort was focused on development of a book on synchrophasor technology to be used for teaching university courses and offering continuing education courses for professionals from industry. The book aims at providing an overview of the current synchrophasor technology and its applications. The book begins with the introduction of the synchrophasor devices, such as phasor measurement units (PMUs), PMU-enabled intelligent electronic devices (IEDs) and phasor data concentrators (PDCs). Then the use of the synchrophasor and synchronized sampling in the areas of transient stability assessment, wide-area stability monitoring and fault analysis is discussed.**

I. Introduction

The use of synchronized measurements, particularly synchrophasors, has a history of over 20 years of research and development. This allows measurements in different locations to be synchronized and time-aligned, then combined to provide a precise, comprehensive view of an entire region or interconnection. Figure 1 shows the locations of currently deployed devices called phasor measurement units (PMUs) that make the synchrophasor measurements available across the North America's electric power grid. In the last few years the effort of deploying and demonstrating variety of applications that can benefit from synchronized measurements has been accelerated through the North American Synchrophasor Initiative (NASPI) and other related industry efforts. Most recently several utilities and regional market operators have developed plans for large scale deployment of such a technology. In the deployment of the Intelligent Electronic Devices (IEDs) for substation synchronized measurement applications, the focus at the moment is on two approaches: a) use of phasor measurement units (PMUs), and b) use of PMU-enabled IEDs such as Digital Fault Recorders (DFRs), Digital Protective Relays (DPRs), Digital Disturbance Recorders (DDRs), etc. that have PMU measurement capability. While the number of dedicated PMUs across the USA utility networks is estimated at close to 1000, the number of PMU-enabled IEDs sold so far is measured in millions.

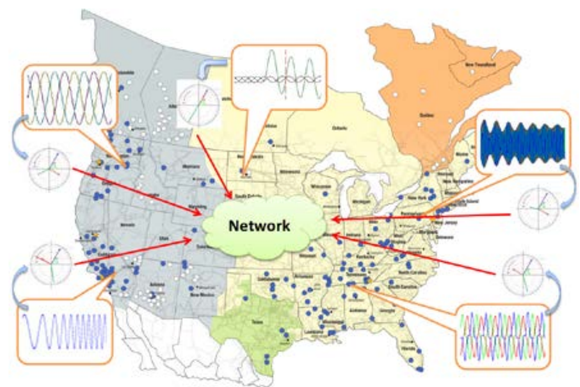

Fig. 1. Synchrophasor measurements aggregated across North America

This book is organized as follows. Section II provides an overview of the technology supporting present day IEDs and PMU functionality. Section III focuses on using decision trees for transient stability assessment by using pre-fault static parameters of the system where the critical thresholds obtained can then be used for preventive control. Section IV gives a summary of recent development in wide-area real-time monitoring tools for large-scale power system based on synchronized wide-area phasor measurements from synchrophasors. Section V discusses the use of synchrophasor and synchronized samplings in the fault location problem.

II. Synchrophasor Devices and Network

A. Phasor Measurement Unit (PMUs)

Synchronization of the measurements can be achieved with the use of a Global Positioning System (GPS) receiver and appropriate hardware. A conceptual view of such a system is illustrated in Figure 2.

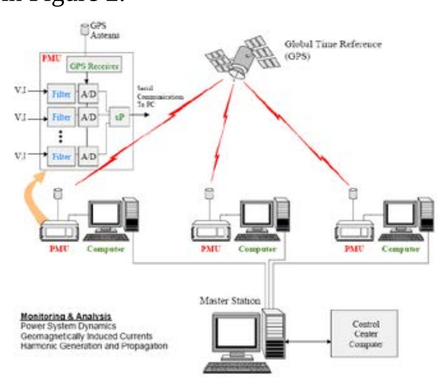

Fig. 2. Hardware platform used by GPS synchronized measurements

The work described in this paper was made possible by funding provided by the U.S. Department of Energy for "The Future Grid to Enable Sustainable Energy Systems," an initiative of the Power Systems Engineering Research Center.

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The Global Positioning System (GPS) receiver has the capability to provide a synchronization signal with precision better than 1 microsecond. This time reference allows the measurement of the phase angle of the fundamental with accuracy 0.02 degrees on a system-wide common reference. The local system (RTU) uses input signals from existing instrument transformers. The captured voltage and current waveforms are time-tagged and transmitted to the energy management system or the master station. Normally, only the first sample needs to be time tagged. Knowing the sampling rate, all other information can be easily extracted. Note that at the energy management system, one can collect all the data with the same time tag. The local systems can be programmed to obtain a set of measurements every 5 seconds, staring at exactly the GPS signal that indicates the arrival of a second. A time reference provided by GPS can provide a very accurate time reference of accuracy better than 1 micro second anywhere on earth. Specifically, the phase of voltage and current can be calculated on almost absolute basis by use of a highly accurate GPS clock. This time reference allows the measurement of the phase angle of the fundamental with accuracy 0.02 degrees on a system-wide common reference.

B. PMU-Enabled IEDs

Presently many IEDs have PMU functionality. Most of relay manufacturers are adding PMU functionality in their line of protective relays. PMUs output real-time streaming synchrophasor data usually in COMTRADE format and at various rates, such as 10, 12, 15, 20, 30, 60 or even 240 for 60 Hz systems [1]. PMUs may also provide positive, negative, zero sequence values, frequency, rate of change of frequency, and so on. Recently many intelligent electronic devices (IEDs) have PMU functionality. Phasor measurement is an added function to the primary functions of a device. Most of the relay manufacturers are adding PMU functionality in their line of protective relays, meters, fault recorders, and so on. As various manufacturers use different algorithms for the phasor calculation, result synchrophasor data may have variations in accuracy and latency.

C. Time Synchronization Options

A PMU requires a source of UTC time and high accuracy timing signal to provide synchronized measurements. According to the IEEE C37.118 standard, the accuracy of a synchrophasor measurement shall not exceed 1% of TVE, which corresponds to a phase angle error of 0.57 degrees [2]. If we only consider the phase angle error, the error of 0.57 degree corresponds to approximately 26 μs at 60 Hz and 32 μs at 50 Hz. The existing methods include the direct GPS signal [3], IRIG-B/PPS [4] and IEEE 1588 [5]-[7]. For using direct GPS signal, an IED must be equipped with GPS receiver for decoding the time signal. For using IRIG-B and PPS, the receiver must be local to the IEDs. Using IEEE PC37.238 [6], the receiver can be either local or remote to the IEDs because the time code defined in IEEE PC37.238 can be distributed over communication network.

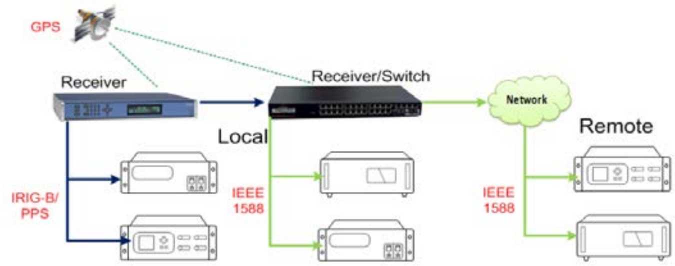

Fig. 3. Time synchronization options

D. Phasor Data Concentrator (PDCs)

The basic functionality of a PDC is to collect data from multiple PMUs, manage the data including time alignment and provide the sum of the data to other entities for various applications [8]. Due to differences in latency and reporting rate of various PMUs, the synchrophasor data measured in same time may not arrive at the same time. PDCs may buffer data for short time duration to produce a validated and time aligned output stream. The PDC will complete the process when all relevant data have arrived or when the maximum waiting time has collapsed. If some of the data are not processed, then it will discard the data and move on to the next process because PDCs do not store the data [8]. Real time data broadcasting capability of PDC enables other utilities to make use of the time aligned data. Each measurement carries a precise time stamp taken from global positioning system of satellites, so that the entire electric grid can be analyzed at any moment in time. PDCs must support the synchrophasor standard, 37.118.1 and 118.2, IEEE1344, PDC stream, and OPC (OLE for Process Control) for real time data transmission. An example of PDC with internal functions is illustrated in Figure 4.

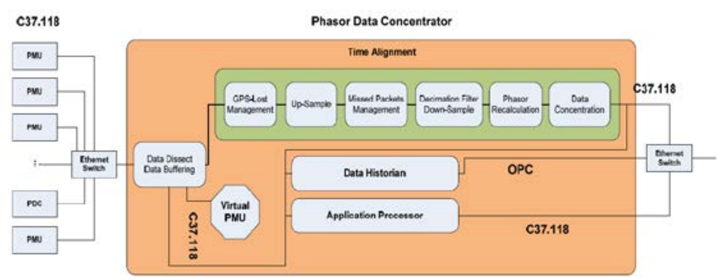

Fig. 4. Phasor data concentrator

III. Online Transient Stability Assessment

With the advent of deregulation in the power industry and with the lack of transmission investment, today's power systems are operated much closer to their limits. The stressed system conditions mean that operators are faced with scenarios that never occurred during the past. One of the main issues that needs to be tackled deals with online dynamic security assessment and control. The objective of this is to ensure that the system can withstand unforeseen contingencies and return to an acceptable steady state condition [9] without transient instability or voltage instability problems. In this section the application of a software tool that uses data mining (decision trees) is discussed. The approach is developed by training a set of trees based on simulations conducted offline. With advances in computer technology it is now possible to create and store large databases that can be used to train agents. In this case the agents are the decision trees and the decision tree building procedure identifies critical attributes and parameter thresholds. In order to evaluate stability limits in terms of critical interface flows and plant generation limits, the use of synchronized measurements from Phasor Measurement Units (PMUs) has been proposed.

The general approaches can be classified into efficient time domain algorithms, direct methods and artificial learning approaches [10]. Figure 5 illustrates this classification.

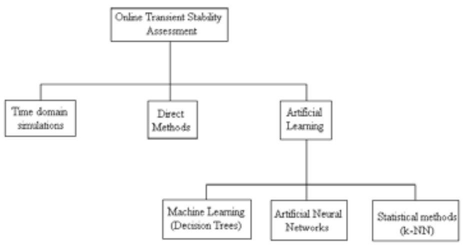

Fig. 5. Classification of online transient stability assessment methods

A. Traditional Time Domain Simulation

Time domain simulation is the most accurate means of determining whether a system will remain stable following a particular contingency. The differential equations of the system are solved step by step using numerical techniques in order to get the actual values of the state variables. These state variable values then yield important information regarding transient stability. Typically the machine swing curves are computed in order to get an estimate of the maximum deviation of machine relative rotor angles. The system dynamics are simulated for the faulted and post fault period. The post fault period is generally of the order of a few seconds during which the system behavior is observed. However, this method is very time consuming and does not yield any information regarding stability margins [9].

B. Direct Methods

The direct methods consist of using Lyapunov's functions in order to assess stability [10]. The Transient Energy Function (TEF) is one such Lyapunov function that can be used to assess stability. It can be thought of as a multi-machine equivalent of the more simplified equal area criterion. The basic idea consists of evaluating the kinetic energy gained by the machines during the fault period and comparing it with the maximum gain in potential energy that the system can withstand (without becoming unstable) after the fault is cleared.

The main advantage of these direct methods is the significant reduction in computing time. Also these methods give an idea of the stability margin of the system and hence help in evaluating the proximity of the system to instability.

C. Artificial Learning

With advances in computer technology coupled with the decreasing cost of mass storage devices, it has become possible to create large databases that can be used to train agents. The underlying principle in this method can be described as follows [11]: 'Given a set of pre-classified examples (learning set) along with their characteristic attributes, derive a general rule (using thresholds) that can explain the input-output relationship of the pre-classified cases and correctly classify new or unseen cases.'

In the context of transient stability assessment, the database would consist of numerous cases that have been assessed using time domain techniques. The attributes would consist of parameters such as generator outputs, critical line flows and relative phase angles. The output could be a stability margin or a simple classification (Secure/Insecure).

D. Decision Trees for Transient Stability Assessment

Transient stability assessment deals with analysis and preventive control. Since the DT based method uses pre fault parameters in order to assess stability, it can be used as an effective approach for preventive control. The use of controllable parameters in decision rules often becomes an important aspect while taking preventive action. In this regard, stability constrained optimal rescheduling of generation is an area that has received considerable attention. Reference [12] deals with the use of the transient energy function (TEF) method of transient stability assessment in order to carry out rescheduling of generation and critical line flows for a given initial operating condition and specified contingency. Reference [13] uses DTs as a tool for security constrained generation redispatch. This approach uses a two-step procedure. The first step consists of running an economic dispatch on all generators without considering security constraints.

$$P_T = P_1 + P_2 + P_3 + ... + P_i \tag{1}$$

Following this, the generator set points are passed through a decision tree which checks the various generator outputs. In case there are no violations the results of the economic dispatch are displayed to the operator. However, in case one of the generators violates a decision rule a generation redispatch is carried out as follows: the decision rule used in the last splitting node of the DT is used as an equality constraint in order to fix the generation of the corresponding unit. Equation (1) now becomes:

$$P_T - P_U = P_1 + P_2 + P_3 + ... + P_{i-1} \tag{2}$$

Thus the total generation now available for dispatch changes to P_T - P_U and this has to be distributed economically amongst *i-1* generators. The above step is repeated iteratively till a secure solution is obtained.

The building of the learning set and its effects on the accuracy of the method is analyzed. Questions related to optimal size of the learning set, selection of candidate attributes and building of multi-class DTs are dealt with. Tradeoffs related to complexity versus number of classes and computational issues relating to the building and deployment of DTs in online environments are discussed. A comprehensive discussion of the method and its critical aspects is provided. The answers provided to different basic questions about the method make it an important piece of literature in this field.

Unlike [13-14], references [15-16] tackle the problem of emergency control using decision trees. Instead of using pre fault static parameters of the system as candidate attributes for building the DT, post fault measurements from a fault that is currently in progress are used. Using this information, the decision tree is used to predict whether the system is moving towards transient instability. Based on the prediction appropriate emergency control action can be initiated.

IV. Wide-Area Stability Monitoring Algorithm

Power system operation is normally required to meet the following four operational reliability properties: 1) Acceptability or viability (all voltages and currents stay within specified acceptable tolerances); 2) Small-signal stability (system dynamics is able to damp out all small-scale disturbances); 3) Transient stability (system dynamics can recover from all credible contingencies); 4) Voltage stability (system dynamics renders operation at nominal viable voltages without degenerating into voltage collapses or voltage declines). This section highlights recent efforts on wide-area real-time monitoring of large-scale power systems using synchrophasors. The research is aimed at developing real-time operational tools related to the three properties 2), 3) and 4) above [17]. Due to limited space, only the voltage stability and small-signal monitoring framework will be introduced in this paper.

A. Voltage Stability Assessment (VSA) Index and Its Motivation

A global voltage security assessment index Γ_i for bus i is defined as the slope of the QV curve:

$$\Gamma_i = \frac{\Delta Q_i}{\Delta V_i} = \sum_j \frac{\Delta Q_{ij}}{\Delta V_i} \tag{3}$$

where ΔQ_{ij} represents reactive power change for each transmission line or transformer (equivalent line mode) connected with this bus. ΔQ_i is an incremental change in bus injection at bus i.

The well-known fact is that power flow Jacobian becomes singular when the system is at a static saddle-node bifurcation. Hence, the slope at the critical point of Q-V curve will be infinite. Or, the VSA index Γ_i will approach zero in the sense of parameter variation of Q_i at bus i when the variation induces a saddle-node bifurcation at the nose of the QV curve.

As for the complementary limit induced bifurcation case introduced in [17], the slope $\Gamma_i = \Delta Q_i / \Delta V_i$ will likely stop at some small value instead of approaching zero when the parameter variation induces the limit induced bifurcation. A statistical algorithm for computation of the slope Γ_i directly from PMU measurements is presented in [17] and has been implemented in Entergy since 2011.

B. Oscillation Monitoring System

Oscillation Monitoring System (OMS) is being developed as a real-time operations toolbox for monitoring the damping ratio, frequency, as well as mode shape [19] of poorly damped electromechanical oscillations in the power system from wide-area PMU measurements. A prototype version of OMS has been implemented as part of the Phasor Data Concentrator at Tennessee Valley Authority (TVA) and Entergy.

OMS includes two engines as shown in the flowchart in Figure 6. The event analysis engine shown in the right side of the flowchart in Figure 6 carries out an automatic Prony type analysis of system responses following disturbances in the system. The complementary damping monitor engine in the left side of the flowchart estimates the damping, frequency as well as mode shape of poorly damped oscillatory modes from ambient PMU measurements whenever such oscillations appear. Details on the two engines can be seen in [19][20].

Figure 7 shows an example of the results from the two engines for a recent event near a major generating plant at TVA. In Figure 6, the system encountered a routine event at about 830 seconds. The event analysis engine of OMS then carries out moving time-window analysis of the PMU measurements towards real-time Prony analysis and concludes the oscillation to be from a local mode (involving mainly one PMU or few nearby PMUs) of 1.2 Hz oscillations with +1.5% damping ratio. On the other hand, the damping monitor engine of OMS analyzes the real-time ambient PMU data continuously, and can estimate the dominant oscillatory mode to be the same local mode identified by Prony at 1.2 Hz with damping ratio of +1.8%. The two engines, namely, the event analysis engine and damping monitor engine serve as complementary engines in identifying the dominant poorly damped oscillatory modes of a power system whenever such modes exist.

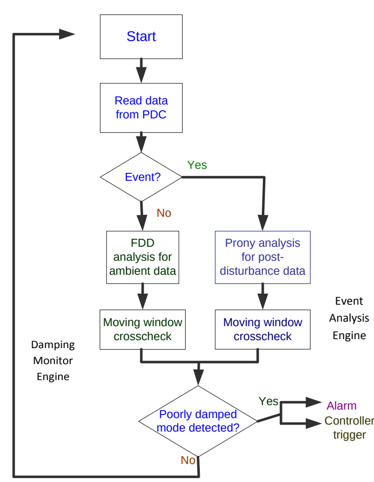

Fig. 6. Flowchart of Oscillation Monitoring System

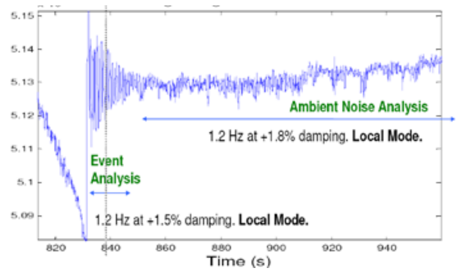

Fig. 7. Illustration of modal estimation results from OMS

V. Fault Location Analysis

Fault location on transmission lines is a very well-known problem which has been studies for a long time [20-26]. With the advent of highly accurate synchronization technology, several new approaches that take advantages of the synchrophasor and synchronized samplings are proposed:

- **Use synchronized sampling at both ends**: A time domain model of a transmission line. Samples of voltages and currents at both ends of a transmission line are taken synchronously and used to calculate fault location [20-22].
- **Use synchrophasors at both ends**: An adaptive fault location technique is derived using the fault index in terms of Clarke components of synchronized voltage and current phasor measurements [23-24].
- **Use of sparsely measured sychrophasors**: Sparse measurement based fault location method using phasor measurements from different substations located near the faulted line can be applied if the measurements are not available from any of the line ends [25-26].

This section only introduces the fault analysis using synchronized sampling at two ends. The details of other methods may be found in the book.

A. Theoretical Formulation

The transmission line considered in this section has a length l and is homogeneous to simplify the presentation. The assumptions can easily be extended to include distributed parameter transmission line models with capacitance included [21-22]. For the simplified consideration, conductance and capacitance are neglected. One line representation of the 3-phase line, with a fault at the distance z from the end S, is represented in Figure 8.

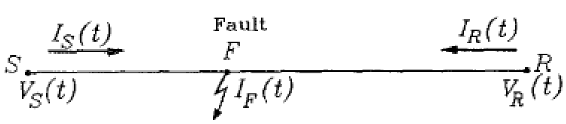

Figure 8. One-line diagram representation of the 3-phase transmission line

The transmission line considered in this section has a length l and is homogeneous to simplify the presentation. As mentioned earlier, the assumptions can easily be extended to include distributed parameter transmission line models with capacitance included.

Location of the fault is based on two vectors defined as:

$$\Delta I(t) = I_S(t) + I_R(t) \tag{4}$$

$$\Delta V(t) = V_S(t) - V_R(t) + l\left[RI_R(t) + L\frac{dI_R(t)}{dt}\right] \tag{5}$$

$V_S(t),\ V_R(t)$	–	Vectors of Phase Voltages
$I_S(t),\ I_R(t),\ I_F(t)$	–	Vectors of Phase Currents
S, R	–	Transmission Line Ends
$R,\ L$	–	Matrices of Self and Mutual Line Parameters

In normal operating conditions, the fault current $I_F(t)$ is zero. As a consequence of Kirchhoff's current and voltage laws, the above vectors are equal to zero.

$$\Delta I(t) = 0 \tag{6}$$

$$\Delta V(t) = 0 \tag{7}$$

If the line is faulted, the values of these vectors are:

$$\Delta I(t) = I_F(t) \tag{8}$$

$$\Delta V(t) = x\left[RI_F(t) + L\frac{dI_F(t)}{dt}\right] \tag{9}$$

The fault current may be eliminated from equations (8) and (9) leading to:

$$\Delta V(t) - x\left[R\Delta I(t) + L\frac{d}{dt}\Delta I(t)\right] = 0 \tag{10}$$

The values of the vectors ΔV(t) and ΔI(t) [equations (4) and (5)] at times n/f_s, where f_s is the sampling frequency, can be calculated from current and voltage samples:

$$\Delta I_n = I_{Sn} + I_{Rn} \tag{11}$$

$$\Delta V_n = V_{Sn} - V_{Rn} + l[RI_{Rn} + f_s L(I_{Rn} - I_{Rn-1})] \tag{12}$$

Here, V_{Sn}, V_{Rn}, I_{Sn} and I_{Rn}, denote vectors of samples taken synchronously at moments n/f_s. It should be noted that the expression for ΔV_n, is an approximate one, since the current derivative cannot be measured. Here, the derivative is approximated with "backward" approximation.

The discrete version of the equation (10) is obtained using the same approximation for the current derivative:

$$\Delta V_n - x\varphi_n = 0 \tag{13}$$

$$\varphi_n = R\Delta I_n + f_s L(\Delta I_n - \Delta I_{n-1}) \tag{14}$$

The fault location is based on equations (13) and (14). In these equations ΔV_n, ΔI_n, and line parameters are known, while the distance x to the fault has to be determined. The number of available scalar equations is equal to 3N, if the samples are taken at N + 1 instant. Since the system of equations is an over-determined one, the most suitable way to find 2 is to apply the Minimum Least Square method. This method provides the following best estimate of x:

$$x = \frac{\sum_{n=2}^{N+1} \langle \Delta V_n, \varphi_n \rangle}{\sum_{n=2}^{N+1} \langle \varphi_n, \varphi_n \rangle} \tag{15}$$

where < , > denotes the scalar product of vectors.

All the principles of fault analysis presented here are based on the fundamental electrical laws only. Derived expressions are valid for any set of voltages and currents at transmission line ends. Consequently, voltages do not need to be balanced; some phase voltages may even be zero. This makes the method completely independent of power system operating conditions. No assumptions about fault currents need to be imposed. The fault resistance may arbitrarily vary in time. Even an inductive component in the fault impedance may be present. This is a unique feature of the presented method.

VI. Conclusion

This paper summarizes the effort related to development of a book on synchrophasor measurement systems and their applications, which is a part of the project task 4.3. Due to page limit, this paper presents only excerpts from the book.

VII. Access to Products

This book will be published in late 2013 or early 2014. The book proposal has been submitted to a publisher for peer evaluation and as soon as the contract is signed, the manuscript will be in production stage.

VIII. Acknowledgements

The authors gratefully acknowledge funding from Power System Engineering Research Center (PSERC), Tennessee Valley Authority (TVA), Entergy, Bonneville Power Administration (BPA), US Department of Energy, and Consortium for Electric Reliability Technology Solutions (CERTS).

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X. Biographies

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Part II

PSERC Future Grid Initiative Proceedings

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Cyber-Physical Systems Security for the Smart Grid

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Peter Sauer, *University of Illinois at Urbana-Champaign*

***Abstract*--This paper focuses on identifying a comprehensive set of cyber security challenges and the need for security at multiple levels of the cyber-physical power system, namely, information security, information and communication technologies (ICT) infrastructure security, and application-level security. It identifies cyber security research issues beyond the traditional ICT security issues. The paper articulates the need for going beyond (N-1) contingency criteria to deal with coordinated cyber attacks. Also, it highlights the inadequacy of traditional models and algorithms that are robust against random, naturally occurring faults to deal with malicious cyber attacks, and hence the need for development of novel models and attack-resilient algorithms which span across generation, transmission, and distribution systems. Finally, the linkage between attack deterrence, prevention, detection, mitigation, and attribution is identified.**

I. Introduction

Cyber security threats against utility assets have been recognized for decades [1]. In the aftermath of the terrorist attacks on September 11, 2001, great attention has been paid to the security of critical infrastructures. Insecure computer systems may lead to catastrophic disruptions, disclosure of sensitive information, and frauds. Cyber threats result from exploitation of cyber system vulnerabilities by users with unauthorized access. A potential cyber threat to supervisory control and data acquisition (SCADA) systems, ranging from computer system to power system aspects, is recognized [2]. The increasing power of the Internet facilitates simultaneous attacks from multiple locations. The highest impact of an attack is when an intruder gains access to the supervisory control access of a SCADA system and launches control actions that may cause catastrophic damages. These attacks can be at the very local level of one relay in a substation to modify protection settings, or on a global level where settings can be changed to affect thousands of customers in homes and business. Another primary concern has been the possibility of massive denial of service (DoS) attacks on the SCADA control system and the resulting impacts on the overall performance and stability of the electric power systems.

Smart grid technologies utilize increased monitoring and control of the electric grid to improve reliability and efficiency. Many smart grid initiatives leverage an increased dependency of ICT to integrate more accurate physical parameter measurements and intelligent controller devices. However, the increased ICT dependency also introduces additional risk from cyber attacks. Analysis of the grid's current security posture has raised numerous inadequacies, including poor system configuration, poor network security and insufficient software security [2]. Additionally, recent events, such as Stuxnet, have shown that attackers are beginning to focus on critical infrastructures and have the ability to develop targeted cyber-physical attacks [3].

Attack resiliency is a key attribute of the next generation electric grid; however, the grid's size, dependency on legacy systems, and physical exposure present numerous security challenges. This requires a forward thinking approach to cyber security, which integrates both novel cyber security protection mechanisms together with comprehensive knowledge about grid operations. This paper introduces current events and government reports, which identify the scope of current cyber security shortcomings. Then, it introduces key smart grid applications and identifies cyber security requirements from both an application and infrastructure perspective. Finally, the paper introduces research efforts that must be addressed to ensure the grid is adequately protected from cyber attack. Specific efforts are identified including:1) Risk Modeling and Mitigation, 2) Attack Resilient Control Algorithms, 3) Coordinated Attack-Defense, 4) Trust Management and Attribution, and 5) Data Sets and Validation.

II. Solving Problems of Grid Integration

Risk is traditionally defined as the product of available threats, system vulnerabilities, and their resulting impact, as shown by the following equation.

$$Risk = Threat\ X\ Vulnerability\ X\ Impact$$

Therefore, the increase or decrease in current threats, vulnerabilities, or impacts will directly reduce the risk from a cyber attack. The threat can be defined as the presence of potential attacks, their motivation, and available resources. Often threat sources can range to unsophisticated individual hackers to more advanced organized criminals, and highly motivated nation-states. Threats are often dynamic and are generally motivated by various political and economic agendas.

The vulnerability of these systems depends on the grid's cyber supporting infrastructure. This typically entails all the computers, software platforms, networks, protocols, and other

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resources required to support grid control and monitoring functions. The grids supporting infrastructure is currently plagued with vulnerabilities due to its heavy dependency on legacy systems, which were not designed from a security perspective.

The risk of cyber attacks is also dependent on the impact that the attack has on the power systems. This will primarily be determined by how the various cyber vulnerabilities impact that grid's various power applications or the set of domain specific control and management functions necessary to control the physical system. An attacker's ability to impact the power application will be the resulting factor in whether it impacts the physical system or not.

Developing a secure power system requires that both the applications and supporting infrastructure are designed to be attack resilient. Unfortunately, the grid's cyber-physical properties and tremendous scope place many constraints on the ability to develop a secure cyber infrastructure. It must be assumed that even within significant infrastructure enhancements, an advanced, persistent attacker will still be able to launch successful attacks. Most current grid control mechanisms have been developed to be tolerant to many traditional physical and environmental faults. However, faults initiated by a human attacker will likely be intelligently designed to bypass these currently engineered.

The smart grid will introduce new applications that rely on cyber infrastructures. Some of them are listed below:

- Advanced Metering Infrastructures (AMI) – set of systems that are deployed to provide two-way communication to all customer power meters. This enables more granular control of consumer consumption, real-time pricing, and distributed generation.
- Distribution Management Systems (DMS) – set of systems required to control lower voltage, consumer level energy distribution.
- Energy Management Systems (EMS) – set of power applications used to control bulk power system generation and transmission.
- Wide Areas Measurement, Protection and Control (WAMPAC) – set of applications that collectively provide phasor measurement unit (PMU)-based wide-area monitoring (state estimation), protection, and control.
- Power markets – Commodity-based energy markets necessary to balance the supply and demand for electricity.

Depending on the nature of each of these applications, we can identify and prioritize security requirements in terms of standard security properties, like Confidentiality (C), Integrity (I), Availability (A), Authentication (AT), and Non-repudiation (N). There could be specific requirements to be satisfied at the Infrastructure level and Application level separately. For example, AMI Infrastructure needs I, AT, C properties to be satisfied, while AMI customer data at the application level mainly needs I, N properties.

A. Cyber Infrastructure Security

As pointed in earlier sections, the cyber infrastructure used to support the grid's control and monitoring functions is currently insufficient. Many software platforms used within the electric grid were developed to operate on legacy systems, which were not designed to be secure from cyber attacks. This software often lacks necessary mechanisms to authenticate all users before allowing system access.

These systems also often lack sufficient access control mechanisms required to constrain provisioned user privileges and perform auditing of user actions. In addition to these software concerns, the networks to support these systems also contain numerous deficiencies. Often the systems and protocols used to communicate SCADA traffic lack adequate encryption and authentication. This means that any unauthorized individual that is able to access the physical network layer will be able to perform man-in-the-middle attacks to manipulated valid control functions.

B. Power Application Security

The power system is functionally divided into generation, transmission and distribution. Each functional division has systems that control specific machines/devices and work using dedicated communication signals and protocols. By this, each control system has its own vulnerabilities, threat vectors and potential impact on power system operation.

1) Generation

The control loops under generation primarily involve controlling the generator power output and terminal voltage. Generation is controlled by local control (e.g., Automatic Voltage Regulator (AVR), Governor Control) and wide-area control (e.g., Automatic Generation Control (AGC)).

The AVR and the governor control are local control loops. They do not depend on the SCADA telemetry infrastructure for their operations as both the terminal voltage and rotor speed are sensed locally. Hence, the attack surface for these control loops is limited.

However, these applications are still vulnerable to malware that could enter the substation networks through other entry points such as portable media. Also, the digital control modules in both control schemes do possess communication links to the plant control center. To target these control loops, an adversary could compromise plant cyber security mechanisms and gain an entry point into the local area network. Once this intrusion is achieved, an adversary can disrupt normal operation by corrupting the logic or settings in the digital control boards. Hence, security measures that validate control commands that originate even within the control center have to be implemented.

AGC relies on tie-line and frequency measurements provided by the SCADA telemetry system. An attack on AGC could have direct impacts on system frequency, stability and economic operation. DoS type of attacks might not have a significant impact on AGC operation unless supplemented with another attack that requires AGC operation. The following research efforts have identified the impact of data corruption and intrusion on the AGC loop.

2) Transmission

The transmission system normally operates at voltages in excess of 13 KV and the components controlled include switching and reactive power support devices. It is the responsibility of the operator to ensure that the power flowing through the lines is within safe operating limits and acceptable voltage is maintained. The following control loops assist the operator in this functionality.

Flexible AC transmission system (FACTS) presents one specific transmission application with potential cyber security implications. The following are attack vectors that are effective in the cooperating FACTS devices (CFD) environment [4].

- Denial Of Service: In this type of attack, flooding the network with spurious packets could jam the communication to some or all the FACTS devices.
This will result in the loss of critical information exchange and thus affect long-term and dynamic control capabilities.

- De-synchronization (Timing-based attacks): The control algorithms employed by CFD are time-dependent and require strict synchronization. An attack of this kind could disrupt steady operation of CFD.

- Data Injection Attacks: This type of attack requires an understanding of the communication protocol. The attack could be used to send incorrect operational data such as status and control information. This may result in unnecessary volt-ampere reactive (VAR) compensation and result in unstable operating conditions.

3) Distribution

The distribution system is responsible for delivering power to the customer. With the emergence of the smart grid, additional control loops that enable direct control of load at the end user level are becoming common. This section identifies key controls that help achieve this.

Modern relays are Internet Protocol (IP) ready and support communication protocols such as IEC 61850. An attack on the relay communication infrastructure or a malicious change to the control logic could result in unscheduled tripping of distribution feeders, leaving load segments unserved.

The smart meters at consumer locations introduce cyber-physical concerns. Control over whether the meter is enabled or disabled and the ability to remotely disable devices through load control switching (LCS) provide potential threats from attackers. Adding additional security into these functions presents interesting challenges. Additionally, meter tampering will likely continue to be a significant problem as consumer's attempt to reduce their energy costs.

C. Human Factors

In addition to security concerns with the cyber infrastructure and power applications, human factors must also be incorporated into the development of a more resilient electric grid. While many grid control functions are closed-loop systems, many large-scale control functions are performed as human-in-the-loop control. Therefore, understanding and enhancing how operators monitor system state, make critical decisions, and perform resulting controls will also critical to the security of the electric grid.

An intelligent attacker with intrinsic knowledge about grid operations and common operator decision processes may be able to devise an attack which exploits these mitigation actions to compound the severity of the cyber attack.

III. Future Research Needs

Research initiatives are required to develop protected cyber infrastructures, secure critical information, and produce resilient power system applications. Smart grid cyber security must combine both cyber and physical system elements [4]. Therefore, this research proposes the following definition for smart grid cyber security.

Smart Grid Cyber Security = Information Security +
Cyber Infrastructure Security +
Power System Application Security

Traditional information security and infrastructure security solutions need to be tailored to the smart grid environment dealing with legacy nature of the infrastructure and the real-time nature of the communication involved. In addition, security must be built into the applications themselves. Conventionally, the power applications (e.g., EMS, markets,) are designed to deal with random faults that occur in the power system or information/communication systems. These are not clearly adequate to deal with malicious faults (cyber attacks) with possibility of coordinated attack events. Therefore, the security of the future grid must have security built in at all three levels to provide defense-in-depth to deal with known and emerging cyber attacks. Developing a secure smart grid environment will require substantial research efforts, which addresses various different areas and approaches. The following section will document critical research areas.

A. Information & Infrastructure Security

1) Communication

Methods are required to protection communication from malicious modifications, denial of service, or spoofing attacks. This requires specially tailored encryption, authentication and access control mechanisms.

2) Device Security

The grid's heavy dependency on embedded systems with for field devices and meters create numerous security concerns, specifically because they are often resource constrained and lack security mechanisms. Additionally, since these devices often lack physical protections, greater device attestation is required to detect malicious modifications.

3) Cyber Security Evaluation

There are increasing security assessment requirements for the electric grid, specifically to achieve compliance requirements for regulatory agencies. This creates a need for methods to accurately assess the infrastructure without negatively affecting system operations. Additionally, research testbeds are required to perform evaluation of assessment techniques without negatively impacting the operational systems.

4) Intrusion Tolerance

Unfortunately, some cyber attacks may bypass protection mechanism. This requires specially tailored intrusion detection systems (IDS) which can detect attacks against the system and protocols used within these environments. Additionally, the development of intrusion tolerant cyber architectures can reduce the severity of a successful attack.

5) Security Management and Awareness

The environment's utilization of different communications and platforms requires the development of new digital forensics capabilities as attacks will likely be different from traditional ICT environments. Additionally, methods to manage and correlate both malicious and normal system events are required to address increasing utilization of cyber assets.

B. Application Level Security

The re-development of current grid control algorithms is imperative to ensure they can tolerate both traditional system faults as well as cyber attack aimed at intentionally manipulating their operation. Algorithm redevelopment should target all system control, monitoring, and protection requirements.

1) Attack-Resilience Control

A resilient industrial control system is one that is designed and operated in a way where the following requirements can be met [5]:

- the occurrence of undesirable incidents can be minimized,
- most of the undesired incidents can be mitigated,
- the impact from undesired events can be minimized,
- the system returns to normal operating point in a short time.

Developing resilient control algorithms that aid in graceful system degradation and quick restoration will aid in minimizing the duration and magnitude of the impact. At the power system level, redundancy will definitely help in reducing the criticality of certain elements. Greater correlation of known physical system state will provide the ability to develop more attack resilient algorithms.

Domain-specific anomaly detection and intrusion tolerance: The development of anomaly-based intrusion detections and intrusion tolerant architectures can also leverage improved cyber event correlations. This is an approach to extract and analyze the data from power instruments and cyber-related logs to distinguish if a threat is credible. Event correlations can be categorized as (i) temporal, (ii) spatial, or (iii) spatial-temporal. These combinations introduce a different perspective of threat that may capture local or global abnormality.

2) Attack-Resilient Wide-Area Monitoring

A cyber attack on the monitoring algorithms can deceive the operators or provide false information about the current operating conditions for several of the EMS applications such as contingency analysis and other emerging wide-area disturbance monitoring applications. Developing attack resiliency in these applications is essential to maintain adequate and accurate situational awareness of the grid operating conditions.

3) Attack-Resilient Wide-Area Protection

Wide-Area Protection (WAP) involves the use of system wide information collected over wide geographic area to perform fast decision-making and switching actions in order to counteract the propagation of large disturbances [6]. The advent of Phasor Measurement Units (PMU) has transformed protection from a local concept into a system level wide-area concept to handle disturbances. The inherent wide-area nature of these schemes presents several vulnerabilities in terms of possible cyber intrusions to hinder or alter the normal functioning of these schemes.

Some of the research challenges and research tasks in developing attack resilient wide-area protection schemes are:

1. Systematically identifying the various vulnerabilities that exist in current and emerging Wide Area Protection Systems.
2. Identifying and classify the different cyber-attack templates on some of the Special Protection Schemes (SPS) architectures. Based on a very generic classification we can identify two main types of cyber attacks that can impact wide-area protection schemes: timing-based and data integrity based attacks.

Some of the research challenges and research tasks in developing attack resilient wide-area protection schemes are:

1. Systematically identifying the various vulnerabilities that exist in current and emerging Wide-Area Protection Systems.
2. Identifying and classifying the different cyber-attack templates on some of the SPS architectures.

C. Risk Modeling and Mitigation

The overarching goal of cyber risk modeling framework for smart grid security should integrate the dynamics of the physical system as well as the operation of the cyber-based control network. The integration of cyber-physical attack/defense modeling with physical system simulation capabilities makes it possible to quantify the potential damage a cyber attack can cause on the physical system in terms of capacity/load loss, stability violations, equipment damage, or economic loss [7]. The integrated model also provides a foundation to design and evaluate effective countermeasures, such as mitigation and resilient algorithms against large-scale cyber attacks. Specific research initiatives include: 1) cyber vulnerability assessments, 2) impact analysis approaches, and 3) mitigation strategies and technologies.

D. Coordinated Attack-Defense

An intelligent coordinated attack would involve a series of attacks launched almost at the same time or within a short span of carefully regulated time intervals in such a way that the primary attack is launched on a critical system component and the follow-up (secondary) attacks are launched on the components that inherently respond to mitigate the failure of that primary component. In other words, if a coordinated attack plan includes actions to nullify the effect of existing mitigation strategies at every step along the way, the physical impact caused could be severe. NERC's High Impact Low Frequency (HILF) report identifies digital relays, remote terminal units (RTU), circuit breakers, static VAR compensators, capacitor bank controllers, demand response systems, meters, plant control systems, plant emission monitoring systems, and EMS as potentially vulnerable elements in the system [8].

E. Trust Management and Attribution

The cyber infrastructure in the power system domain can be viewed as interconnected "islands of automation". This interconnection brings about inherent trust concerns as vulnerabilities in other domains may abuse trust relationships [9]. In addition, if an organization has a system affected by a security event, that information may not be communicated to all concerned domains, therefore, the decreased trust is not appropriately communicated to all the other systems. Key research initiatives include: 1) trust management lifecycles, 2) formal trust relationships, 3) insider threat management, and 4) attack attribution.

F. Data Sets and Validation

Performing research within this domain is often constrained by the lack of accurate data about current system deployments. This requires that research make often inaccurate assumptions, and therefore, limits the applicability of the results. The development of accurate datasets is necessary to ensure academic efforts can be transitioned to current environments. Key research initiatives include: 1) cyber/physical data sets, 2) cyber attack data sets, and 3) realistic cyber-physical testbeds.

IV. CONCLUSIONS

The development of an attack resilient electric grid is necessary to address increasing concerns to the security of the nation's critical infrastructure. As cyber attacks become more prevalent, attackers are expanding their focus to address industrial control system environments, such as the electric grid. Additionally, as the deployment of smart grid technologies expand, the grid becomes increasingly dependent on ICT for control and monitoring functions which introduces greater exposure to cyber attacks.

The development of an attack resilient electric grid requires substantial research efforts, which explore methods to create a secure supporting infrastructure along with robust power applications. The developing of a secure cyber infrastructure will limit an attacker's ability to gain unauthorized access to critical grid resources. Infrastructure security enhancements require the expansion and tailoring of current cyber protection mechanisms such as authentication, encryption, access control, and intrusion detection systems. Unfortunately infrastructure level protection mechanisms may not prevent all cyber attacks. The development of more robust control applications will ensure the grid can still operate reliably during an attack by leveraging information about expected system states and operating conditions.

This report introduces future research initiatives that should be addressed to ensure the grid maintains adequate attack resilience. The developments of strong risk modeling techniques are required to help quantify risks from both a cyber and physical perspective. Improved risk mitigation efforts are also required focusing on both the infrastructure and application perspectives. Particularly, *attack resilient control algorithms* should be developed to utilize increased system knowledge to reduce the impact from a successful attack. Risk information must also be provided to operators and administrators through the development of *real-time visualization* mechanisms, which can be integrated with current grid monitoring functions to assist in the development of appropriate attack responses.

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VII. Biographies

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Future Grid: The Environment

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***Abstract*—The electric energy industry faces three significant environmental issues: greenhouse gas mitigation, climate change adaptation, and availability of water. Electric vehicle loads are also increasing as the transportation industry addresses greenhouse gas emissions. The issues interact; addressing one may improve or worsen the others. Technologies exist or are in development that will help address each. Research is required for each to determine the magnitude of response needed by the industry and the most cost-effective responses that will assure continued reliability. Addressing these issues will increase the cost of providing electricity, which is critical to national and world economies. Regulations should be carefully evaluated before implementation to insure their effectiveness.**

I. Introduction

The objective of this paper is to present the significant near- and long-term unresolved environmental issues relevant to the electric energy industry, and to summarize the technologies that will help resolve them. The issues are those that the industry will be addressing in the coming years. The issues are complex, with significant interactions among costs to the industry and its customers; benefits to the industry, its customers, and society; and reliability of the electric supply. Electricity is critical to the national and world economies, so anything that affects the electric supply industry also has significant economic effects. Many of the environmental concerns, such as adapting to the effects of climate change, also have very high potential costs if not addressed, and are thus also important to the world's economy.

All the issues presented will have to be addressed by the industry. Some of the issues presented are being addressed in the U.S., some need additional work, and others are not being adequately addressed. Progress has been made on some in other countries. The questions presented are those that must be addressed within the next century by the electric energy industry, policymakers, regulators, and researchers.

The industry will face regulations on most of these issues and it is important that those regulations be effective, actually addressing the environmental issues as intended. The electric energy supply and delivery system is extremely large and complex, so regulations can have unintended or counterproductive consequences. Multiple regulations interact and can also produce unintended results. Careful research and consideration of the environmental needs and the goals of regulations is needed before they are put into place.

II. Unresolved Environmental Issues Facing the U.S. Electric Energy Industry

Three critical environmental issues face the electric energy industry in the years ahead: mitigation of greenhouse gas emissions, adaptation of the industry to changing global and regional climates, and the availability of water for electric generation. There are technologies in development such as carbon capture and storage that directly address some of these issues. There are other technologies, some of which are commercial and some that are not, such as increasing the use of nuclear generation and improved energy efficiency, that are being considered to help address these issues. Some technologies address all three issues, but others may address one or two but be detrimental to others.

These three issues will eventually be addressed through significant new environmental regulations at the federal and state levels. Some of the regulations will require large investments by the industry in new technologies, some of which are not yet commercially available. The issues of limiting pollutant emissions and shared societal use of water are appropriately addressed through government regulations because they are not intrinsic to markets; such issues are referred to as externalities since they are external to market theory.

A variety of state and regional regulations now address these issues. Regulating on state and regional levels pose problems to the many utilities that operate in more than one state. Differing and conflicting regulations from one state to another require significant resources to track and comply with each state's regulations. For this reason, federal regulations are preferable to state or regional regulations that exist now in response to perceived lack of needed action at the federal level.

A. Greenhouse Gas Mitigation

In 2009, the electric power sector produced 39.8% of total CO_2 emissions in the U.S. [1]. The industry also uses SF_6, another greenhouse gas, as an insulator in high voltage

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equipment. While the volume of SF_6 is miniscule compared to CO_2, it has 16,000-22,000 times the global warming effect of CO_2, depending on the time frame considered [2]. Regulations on the use and release of SF_6 will continue to tighten in the future. But because of the volume of CO_2 involved (the U.S. sector emitted 2,160 million metric tons in 2009) and the expense of removing carbon from fuel or exhaust streams or replacing fossil-fired with carbon neutral generators, CO_2 mitigation will be the most costly.

A 2007 PSERC report [3] provided a detailed analysis of how the need to mitigate GHG emissions in response to global climate change will affect the electric energy industry. No federal action has been taken since that report was published. The climate science community, however, is observing that climate change is happening faster than was predicted at the time of that report [4]. The 4th IPCC report [5] used a conservative model for the melting of polar ice because of questions about the ice models available at the time. Recent changes in polar ice have occurred at a much faster rate than the report predicted. In the absence of federal regulations, state and local governments have taken actions outlined in the previous section on existing regulations. Widely differing state, local, and regional regulations, and uncertainty about the form and timing of federal regulations, make it difficult for the industry to know how to plan long-term for GHG mitigation.

Numerous technologies are being considered for reduction of electric industry GHG emissions, and these are discussed in the next section of this paper. Other industries besides electric energy, most notably transportation, will also be required to reduce CO_2 emissions. In 2009 transportation was responsible for 34.1% of CO_2 emissions in the U.S. [1], just behind the electric energy sector. A growing part of the transportation industry's response is to switch to electric vehicles. While this provides load growth for the electric industry, it also shifts a greater part of the burden of decreasing CO_2 to the industry.

The climate science community is nearly unanimous in its support for federal regulations on all U.S. industries to reduce GHG emissions in the coming years. Actually reducing the emissions of CO_2 from electric generation is a highly complex undertaking because of the size and complexity of the interconnected electric production and delivery system. Technologies and policies that would seemingly produce obvious reductions in emissions may not produce the reductions expected.

B. Climate Change Adaptation

The 2007 PSERC report stated well the issue underlying the industry's need to adapt to climate change: "*Electricity assets have been designed on the basis of historic climate data and a period of relatively stable weather*" [3]. Climate change affects these assets in many ways. Some of these effects are already being seen, and the industry needs to move quickly to begin adapting to changing climate, and to form a long-term plan for adaptation. Effects include:

1) Higher Average Air and Water Temperatures

The most direct effect of climate change is higher average air and water temperatures. Average global temperature increases of 1-2° C are projected for 2050, and 1.5-5° C by 2100 [5].

Because so much electric load is temperature-dependent, this increase will have a direct effect on energy consumption and peak load patterns. The use of air conditioning for cooling is expected to increase significantly, producing higher summer peak loads and greater total electric energy consumption [6]. Higher overnight temperatures reduce cooling times for transformers and other assets and will produce higher failure rates.

Population migration is expected, especially in response to failures of agricultural areas. This may also prompt increased urbanization, creating additional capacity and reliability challenges for urban utilities, as well as a potential increase in the number of customers unable to pay for their electricity needs.

Ratings of transmission and distribution lines and thermal generating units are dependent on ambient air and cooling water temperatures. Higher temperatures will reduce the capacity to generate and deliver electricity at the same time as demand is increasing.

Snow and ice will melt as temperatures rise. This will initially increase runoff and hydroelectric production. But as long-term snow and ice levels are reduced because of warmer winter months, runoff will decrease and reduce hydro generation availability. The integrity of some structures built on permafrost will be compromised. Production of oil and natural gas in these areas may be reduced.

Research is needed to quantify the scope of increased loads and decreased generation and delivery, and possibly fuel production, capacities due to higher average temperatures. Planning models need to be developed that include these issues. With these models the industry can address the potential capacity and reliability issues involved.

2) Rising Sea Levels/Land Subsidence

As temperatures rise and existing snow and ice melts, sea levels will rise, and ocean salinity will change. Average sea level increases of between 25 and 50 cm are projected by 2050, and rises of 70-180 cm by 2100 [7]. Such increases place assets located near sea level at risk. Besides being directly affected by water level increase, land subsidence in some areas caused by increased erosion and oil and gas extraction is also becoming more of an issue. Parts of the Louisiana coast, for example, are expected to subside by 30 cm by 2050 [7]. Increased storm surge, resulting from rising sea levels and increased severity and frequency of extreme weather, discussed in the next section, further threatens assets near sea level. The industry needs to identify all potentially affected assets and plan for retirements or retrofits of these assets.

3) Severe Weather

Climate change is expected to result in more severe weather and extreme weather patterns. Increases are projected in the frequency, severity and duration of wind, including hurricanes, cyclones, and tornadoes, ice, hail, and thunderstorms. For the U.S. Gulf coast, for example, a one in

100 year severe weather event today is projected to become a one in 40 year event by 2100 [8]. These expected changes have many implications for the electric energy supply system.

Wind and ice are the major load components for transmission and distribution line designs. A British Columbia study forecasts that storms will exceed design standards for lines and hardware [9]. Existing designs need to be evaluated and upgraded for increased wind and ice loading, and new designs are needed. Increased lightning activity has direct implications for transmission reliability. An increase in forest fires due to lightning is also projected, threatening assets located in forests. The industry must identify threatened assets and schedule upgrades or replacements as part of long-term planning.

While average global temperature increases are expected to be in single digits, the high and low temperatures associated with the averages are expected to increase. This is a regional phenomenon, with summer high temperatures in some areas expected to increase and winter low temperatures to decrease. Periods of extreme heat or cold are expected to grow longer. Such changes in temperature affect the thermal ratings of generation and delivery assets, and can have reliability effects in the case of extended periods of high temperatures and higher nighttime summer temperatures.

Access to transmission lines for maintenance, especially by helicopter, will be hampered by increased fog and severe weather. Fog will also increase the likelihood of cloud icing and flashover. Severe weather may also affect the overall economy in some regions through reduced growth and reinvestment. Production of fossil fuels, especially by undersea oil and gas platforms and flooding of coal mines, may also be affected. An expected increase in flooding is discussed in the following section.

4) Changing Precipitation Patterns

Precipitation patterns are projected to change with increasing global temperatures. The changes will vary by region, so each area must be evaluated individually. In some areas higher total rain and snow are expected. Runoff is projected to increase, for example, by up to 40% by 2050 at higher latitudes [5]. This increase will result in more erosion, flooding and mudslides. Trees will fall because of weakened root systems. In some cases lakes will overfill and dam security may be threatened. Corrosion rates will increase on transmission towers, hardware, and conductors. Hydro turbines may be damaged by increased sediment flows.

In other areas, less precipitation is expected. Runoff is projected to decrease by as much as 30% at mid-latitudes by 2050 [5]. Many semi-arid areas, including parts of the western United States, will experience a decrease in water resources due to climate change. Droughts will increase in severity and frequency. In these areas there will be increasing competition for water resources, which will magnify the water issues discussed in the next section.

Climate changes will in some areas affect existing wind and sunlight patterns [10]. Resource availability for wind and solar generation may increase or decrease. Existing wind turbine and solar thermal and PV generator availability will change accordingly. Changes in wind speed, gusts, turbulence, and prevailing direction will increase structural failures of many assets, increase recovery time, and reduce overall reliability.

5) Changing Vegetation

Changes in climate patterns naturally affect the vegetation that is growing in an area, and can affect growth rates and other characteristics of existing vegetation. This can have a significant effect on crops, resulting in increases or decreases in irrigation loads and population migrations of agricultural personnel out of some areas and into others. Biomass crops will be among those affected, potentially making more or less such crops available, depending on the region.

Asset-related vegetation control will also need to be reassessed. Transmission line rights of way may require more, or less, work to maintain. Transmission and other asset owners will have to adapt to increased or decreased growth rates and new forms of vegetation.

6) Changes to Insect and Animal Populations

Like vegetation, insect and animal populations will also be affected by climate change. Existing species may proliferate, or be reduced, by climate change. New species will move into previously unpopulated areas and out of others, and their effects on the electric power system will go with them. For example, mountain pine beetles have moved into British Columbia in recent years. The resulting death of pine trees increases forest fire risk. The eventual loss of forested areas alters water flow and hydrologic profiles and can contribute to increased flooding, erosion, and mudslides. Wood supply for poles and other assets may be affected.

Likewise woodpeckers and the tree and pole damage they cause will proliferate in areas where they did not exist before. Changing and migrating populations of squirrels, raccoons, snakes, raptors, and other animals will affect transmission and distribution reliability. Burrowing animals will undermine structures.

C. Availability of Water

Most electric generating technologies use water from external sources in their operation. Water use is considered in two ways. The first is water withdrawal, water that is drawn from sources such as rivers and lakes but is then returned to the source after use. Cooling water for a thermoelectric generator using a once-through cooling system is an example of water withdrawal. The water must be available, usually in large quantities, but the net water removed from the source is much less than what is withdrawn. The water returned to the source is available for other uses or reuse.

Water consumption is water withdrawn from sources, including groundwater, that evaporates or is otherwise used and is not returned to the source. In a once-through cooling system, the water that evaporates during use is water consumed by the cooling system. This water is no longer available for any use until it returns as precipitation.

Water use in the extraction, production, and transportation of fuel for generation must also be considered. Such water use will often be in a different geographical location than the generator, which complicates the analysis.

Hydroelectric generation is directly affected by the availability of water. Climate change, as discussed previously, is expected to change the amount, intensity, and annual schedule of precipitation and snowmelt in many areas. These may affect the long-term availability of hydro capacity, increasing it in some areas, decreasing it in others, and changing the monthly availability in both. For example, hydro generators that rely on glacial melt will first experience an increase in water availability as glaciers melt. That availability will decrease, however, after the glaciers have reached a new, smaller, steady-state [11].

As climate changes, other purposes of the hydroelectric reservoirs, such as flood control, water supply, and recreation, will also be affected, and these needs may in turn affect water availability for electric generation. Evaporation from reservoirs will also increase as average global temperatures increase. Hydro is often very flexible generation and is thus relied on in some areas for peaking energy and ancillary services such as reserves. Its availability for these must also be considered in long-term electricity planning.

As world population increases, demands for water for human consumption, agriculture, and electricity production also increase, and future shortages are expected in some regions of the U.S.

The availability of water is regional, with large differences in availability sometimes occurring over relatively small distances. Water availability is also being affected by climate change, as discussed in the previous sections. As the demand for water and electricity increase, providers of electricity must consider how much water will be available for use in electric generation and in the production of fuel for those generators. Generation technologies and fuels that withdraw and consume less water will become more important, and technological improvements to reduce water use by generators and fuel production are needed.

III. Technologies to Resolve the Critical Issues

A wide range of technologies are available, and others are in development, that will help address the environmental issues presented in this paper. Some technologies will address multiple issues, while some will address one issue but make others worse. The implications for multiple issues must be considered for each technology, and for combinations of technologies. The costs and reliability implications must also be considered.

To reduce the CO_2 emissions of the electric industry using existing generation, natural gas fired plants can be more heavily loaded, allowing the output of coal fired units to be reduced. Minimum outputs, ramping, and other constraints will set the upper limits of this fuel switching technique, but it can provide some significant reductions in CO_2 emissions. Increased use of natural gas will result in price increases in the fuel, and the environmental effects, including water use, of hydraulic fracturing and other advanced recovery techniques now being used to increase U.S. production of natural gas must be considered.

Another option for CO_2 reduction is to capture, either in the fuel or exhaust streams, and store the carbon from low-cost coal-fired generation before it is released into the atmosphere. Carbon capture and storage (CCS) is being done and is feasible [12], but it will add significantly to the cost of coal-fired generation. The environmental effects of transportation of coal should also be considered in the assessment of future coal use.

Nuclear fission electric generation is an already-mature carbon-neutral technology, and increased use of nuclear generation would reduce CO_2 emissions. Public acceptance of new nuclear plants, however, especially after radiation leaks that resulted from the recent Japanese earthquake, is uncertain [13].

Natural gas, coal, and nuclear generation are all thermal technologies that have significant cooling water requirements. Cooling systems can be designed or modified to reduce water use, and this will be important in water-limited regions.

The use of renewable energy has increased rapidly over the past few years, driven partly by the desire to reduce GHG emissions. Non-thermal renewables offer much lower water requirements as well. Renewable technologies themselves are carbon-neutral, but they require backup generation, usually natural gas, the participation of responsive demand, or energy storage to maintain grid reliability, so they are not necessarily completely environmentally neutral. Smart grid technologies which allow load to be integrated into system and market operations can be used to have aggregated load mitigate wind and solar variability. Energy storage has the potential to serve as backup for renewables, but storage costs are still high, adding at least $0.05/kWh to the cost of electricity [14]. Storage without renewables may also be useful in reducing emissions.

Improved energy efficiency reduces the amount of electric energy generated, and thus reduces GHG emissions and water use from generation. Efficiency improvements can be made in both the T&D systems and on the consumer side. Demand-side efforts to influence electricity use can also be useful in reducing emissions.

Many electric system assets are threatened by rising sea levels and increased severe weather in the coming decades. Rising sea levels can be addressed by seawalls or other water control technologies, or by relocating assets. Severe weather will in some cases require more robust asset design that can withstand more severe and more frequent storms.

IV. Other Issues

A. Electric Vehicles

New environmental policies will affect other industries besides electric generation. Because of transportation's reliance on petroleum fuels, the transportation industry is second after electric energy in production of GHGs in the U.S. [1]. Options for reducing those emissions include switching to electricity as the energy source for transportation. The GHG production is then shifted from transportation to electricity.

With the current electric generation mix and transportation fuel efficiency, EVs offer some benefits in GHG reduction. As the GHG output of the electric system is reduced, that benefit can increase significantly. Electric vehicles (EVs) also offer benefits to consumers of lower energy prices and decreased price volatility [16]. Water use comparisons should take a life cycle approach that includes the geographic issues in water availability.

High penetrations of EVs offer a significant new load and also significant challenges to the electric industry. If new generation is to be avoided, most of the vehicle charging will need to be at night, and new smart grid systems to schedule charging will be needed. Increased night loading will have system reliability effects, as reduced overnight loading, which allows component cooling, is part of the conventional electric system design. These and many other issues must be considered as the use of EVs increases.

B. Life cycle Planning for Future Environmental Regulations

Long-term planning for the electric energy industry has always been a complex activity. With these significant new environmental issues to be considered, it becomes even more so. Designing the system to optimally address the issues of GHGs, adaptation, and water in the years ahead requires complete understanding of the issues, their interactions, and how industry technologies and techniques actually affect each. Life cycle analysis assesses the environmental impacts and costs of each technology in a complete way, from raw materials needed in construction, through fuel production, delivery, and use, through waste disposal during and at the end of life [16]. Such analysis can help assess the optimal strategies in addressing the complex and often conflicting environmental issues. Long term electric industry planning requires substantial information to achieve further improvements. Life cycle analysis can find opportunities for improvement and potential areas of sustainability impact for the power generation sector.

C. Interactions Among and Secondary Effects of Regulations

As discussed in the previous section, the environmental issues and regulations intended to address them have numerous interactions and are dependent on many factors including geography and time. The issues often conflict. A recent PSERC report [17], for example, found that a cap and trade system for CO_2 emissions will significantly affect other emissions, such as SO2 and NOx, and the demand for and price of permits for those emissions. Cap and trade for multiple pollutants can result in extreme price volatility and uncertainty for those markets. Permit prices can also be strongly dependent on weather and other external factors, with high prices and limited permit availability during periods of high demand, or a drought that limits the availability of hydroelectric generation.

Those creating environmental policies and regulations must insure that they are effective in addressing the intended issues, and must understand their effects on other issues. The potential interactions among all the environmental issues are significant and must be considered when designing programs to mitigate them. New regulations and policies must be thoroughly tested before implementation.

V. Future Research Needs

A. Greenhouse Gas Mitigation

A substantial amount of research is needed to create and verify the effectiveness of regulations and market mechanisms that will reduce electric industry CO_2 emissions while meeting other environmental goals and the economic and reliability needs of the industry and its customers.

B. Adapting to Climate Change

Research is needed to develop detailed forecasts of each potential climate change effect. The ability of existing infrastructure to meet energy needs during extreme temperatures and to withstand more frequent and severe weather events also needs to be better understood. These must then be built into planning models so that the industry can begin the necessary adaptation measures. Financing and rate adjustments will be needed to allow changes to be made before assets are actually affected and reliability degraded.

C. Availability of Water

Significant research is needed to determine the regional availability of water to the electric energy industry, and the technologies that will help the industry reduce water use when necessary. This research will guide the industry in planning the future generation supply.

VI. Conclusions

The electric energy industry in the U.S. has been addressing environmental issues associated with the production and delivery of electricity since the 1940s. Three significant new concerns now face the industry: reductions in the production of greenhouse gases, particularly CO_2; adapting to the changing climate; and the availability of water. Technologies exist to address these issues, and new technologies are under development. The issues are appropriately addressed through government regulations since they are not intrinsic to markets, and new policies and regulations will be created to address them. At the same time, the use of electric vehicles will increase as the transportation industry also addresses these same environmental issues. High penetrations of electric vehicles present new challenges to the electricity industry that also must be addressed.

The environmental issues, technologies, and regulations all interact and at times conflict; none may be addressed without considering the life cycle effects on the others. All will affect the cost of producing and delivering electricity. Electricity and its cost are critical to the U.S. and world economies, so potential costs must be balanced against the benefits of improving, or the costs of not improving, the environment. Environmental costs and benefits from actions today are forecast to occur over a period of decades, so analyses should use appropriate time horizons. Electricity planning should consider life cycle costs and benefits, and must optimize the long-term environmental benefits, electric system reliability, and costs of implementation.

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IX. Biographies

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Centralized and Distributed Generated Power Systems - A Comparison Approach

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***Abstract*--The Central Generation (CG) has been in dominant use in legacy power systems, serving large consumptions of power but with a variety of problems including its cost, sustainability, and resiliency challenges in the long run. On the other hand, Distributed Generation (DG) is smaller in design and power generation, primarily designed for renewable energy resources (RER) such as wind and solar. The analysis made in this paper is based on the use of engineering judgment to determine the extent to which the economies of scale of DG and CG can be used to maximize the performance of the future grid. Performance** Indices **are proposed to quantify and investigate the pros and cons of DG and/or CG and/or combination of the two. This approach will meet the challenges of developing the future electric.**

I. Introduction

Increased interest in the combination of CG and DG necessitates the development of new indices to evaluate the relative benefits and weaknesses of CG and DG especially with respect to combining them in the future electric grid infrastructure. These indices can also serve as the benchmark for planning and operation decision. The proposed indices are based on economy of scale studies of DG relative to CG, assessment of the robustness of DG and CG under different load conditions, assessment of DG and CG capability and resiliency to handling unforeseen events amongst others.

This paper attempt to answer the following questions:

1. To what extent are economies of scale still relevant for CG/DG?
2. Which is the most cost effective combination of DG and CG infrastructure?
3. To what extent does DG or CG improve system resilience to unforeseen events?
4. What is the most attractive combination of DG and CG infrastructures to maximize system resilience due to unforeseen events?
5. To what extent does DG or CG improve sustainability (i.e. decrease emissions and diminish other environmental impacts)?
6. What is the most attractive combination of DG and CG infrastructures to maximize system sustainability?

A. Central Generation

Central Generation (CG) is electric power production architecture such that bulk power is produced from central power plant(s). Most large central generators are fueled from fossil fuel (coal, gas), large hydro and nuclear fuel. These large plants are more complex, expensive, costly to manage and require a number of years to construct. CG plants are susceptible to unreliability and instability under unforeseeable events, and are often vulnerable to attacks. Their limitations, in terms of efficiency and environmental impact as well as resiliency, have motivated the rise in the use of renewable energy resource.

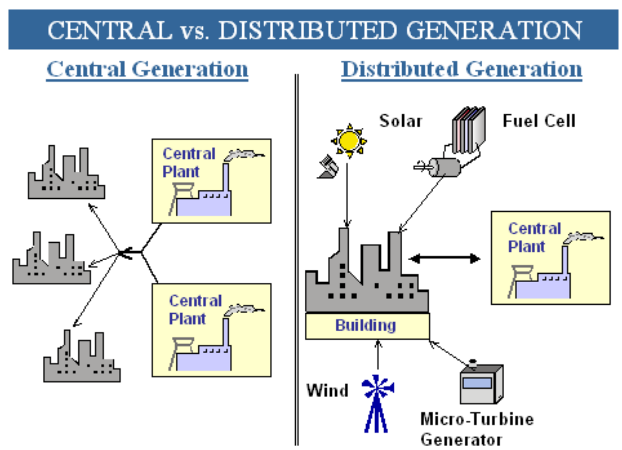

Fig. 1. Comparison of CG, DG[10]

B. Distributed Generation

DG is a power production architecture that allows the utilization of small power source and locating them close to the consumers. Most DG sources are characterized by size (small-scale), sustainability and environmental friendliness. Examples include photovoltaic, wind, small hydro, fuel cells, concentrated solar generators, biomass fired generators and other renewable energy resources (RER). However when reliability and power quality issues are critical, DG most often includes more traditional fossil fuel fired reciprocating engines or gas turbines. DG is not a new concept, a number of utility consumers have been using DG for decades. Over the last 10 years, the DG market has been somewhat on the increase. In the late 1990s, new regulations/subsidies, such as net metering and renewable portfolio requirements, and the development of new DG technologies, have sparked broader interests in distributed generation.

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Throughout this paper, large wind farms and large PV installations that are interconnected to the transmission system are considered CG. Both a centralized generated grid system and a distributed generated grid system have their merits and demerits. Thus, this paper aims at enumerating both positive and negative aspects of the grids as well as addressing the challenges posed by the grids. This analysis helps to assess the best option that may enhance the reliability, resiliency and sustainability of the future grid architectures.

II. APPROACH/METHOD

CG, DG and their combination are compared based on three indices: economy of scale, resiliency and sustainability. These indexes are important to determining the most effective combination of CG/DG aimed at meeting the needs of the future electric grid. Analyses made in this paper are based on engineering judgment.

III. RESULTS

A. Economic of CG and DG Systems

DG and CG can be compared based on various economic indices such as capital expenditure (CAPEX), operational expenditure (OPEX), marginal price of power produce from DG or CG to the customer, and to the utility, cost of reliability and outage cost. Table I itemizes a comparison of DG and CG based the identified economic indices.

Centralized Generated (CG) systems have a high cost of installation and maintenance; however its usage is mainly from a central location. When compared to maintenance requirements of several installed DG system, CG is cheaper due to economy of scale and also because it is a mature technology. However the reduction in losses because DG's are located closer to the consumer and the lower fixed and variable OPEX associated with DG operation compensates for some of the large initial CAPEX. Also if a cost is placed on reliability and environmental pollution the economics of DG and CG fall in the same range. Therefore a careful combination of CG and DG allows each technology to complement each other thus resulting in a power system that is more efficient and more economically viable. For example large cost associated with transmission congestion have necessitated the need to limit power flows in transmission systems and because we cannot control the power consumption at will, integrating DG's can free up capacity for efficient transmission.

TABLE I
COMPARISON OF THE ECONOMICS OF DG/CG

Component Cost	Centralized Generation (CG)	Distributed Generation (DG)	comments
Cost of Capital	Lower Cost per unit	Higher cost per unit	The CAPEX for DG's especially RER is expected to reduce as the technologies becomes mature.
Fixed Operation and Maintenance Cost	Higher	Lower	Various incentives from governments for DG installation is also contributing reducing fixed O&M
Variable Operation and Maintenance Cost	Higher	Lower	Lower cost are due to the fact that most DG 's utilizes renewable energy resources which are free. Hence, electricity cost/kWh is also lower
Fuel cost	High	Low	Most DG's utilizes fuel that is naturally available and free hence the cost per kWh is lower.
Transmission	High voltage transmission is mandatory High losses and transmission failure	Only distribution required Reduced capital cost	This results in a reduced cost for the power grid with the combined CG and DG.
Expense for unserved Energy	High	Low	

B. Resilience of CG and DG Systems

Resilience is the ability of a system to respond and recover from an event. In other words, it is the response of the system to recover from a catastrophic event such as a hurricane, or earthquake. The resiliency prevalent in either a CG or DG system is the property associated with the system's ability to appropriately compensate for increased or decreased load demand by appropriately increasing or decreasing supplied power. Resiliency requirements in a CG are therefore not the same as that necessary for a DG. This is because the load demand required for a CG is higher than a DG. In compensating this higher load demand for a CG, recall that that the installed capacity for the CG is greater than DG.

A resiliency metric for either DG or CG systems is defined as [4]:

$$R(x,u) = \int_t^n [\ \sum_{i=1}^n c_i f_i(x,u)]dt \tag{1}$$

Where $f_i(.)$ is the routine task, such as power supply and transmission transactions, and/or communication services, with weight coefficient c_i as an associated cost at a given time scale; x and u are the state and control variables, respectively.

DG's are expected to be more resilient than CG; Resiliency in DG systems is high due to better self-healing capability as compared to CG. However greater resiliency is achieved with the combination of CG and DG in power networks. Fault cases in CG have less severe impacts on the grid because they serve smaller regions than CG. In extreme cases of natural disasters such as hurricanes and tornadoes leading to faults on the grid, a CG-based network will be more susceptible to failure as compared to a DG network with planned islanding capabilities.

As CG/DG based power systems continue to grow in size, and capabilities, the reliability is being pushed to its limit. While power engineers try as much as possible to ensure that there is constant power availability to users, considerations for some natural disasters such as earthquakes, hurricanes, tornadoes, and snow storms, [5] is required to ensure availability of continued power to consumers. Measures of reliability [8, 9] are defined as:

Expected Unserved Energy (EUE) is a measure of the bulk (generation/transmission) system capability to continuously serve all loads at all delivery points while satisfying all planning criteria. The following information's is required for the computation of EUE:

1. Frequency of each contingency (outage/year)
2. Duration of each contingency (hour /outage)
3. Unserved MW load for each contingency

EUE = sum of all the probabilistic weighted unserved MW for each contingency.

Where:

$$EUE = \frac{\sum_{i=1}^{N}\sum_{y=1}^{Y}\sum_{d=1}^{D}\sum_{h=1}^{H} E_h}{N_h} \quad (2)$$

EUE = Expected Unserved Energy (MW-hours/hour)
N = the number of Monte Carlo simulations for the period, which is typically one year using hourly level of granularity
Y = number of years in the study
D = number of days in each year that are simulated
H = number of hours in each day that are simulated
E_h = the amount of unserved energy for this hour (in megawatt-hours)
N_h = the total number of hours simulated in the Monte Carlo study.

Loss of Load Probability (LOLP) in units of percent, measures the probability that at least one generation shortfall event will occur over the time period being evaluated.

Where:

$$LOLP = \frac{\sum_{i=1}^{N} S_e}{N} \quad (3)$$

LOLP = Loss of Load Probability (%)
S_e = Simulation in which at least one significant event occurs.
N = the number of a Monte Carlo simulations for the period, which is typically one year.

The distributed nature of DG and its closeness to the customers reduces the annual unserved energy (in megawatt-hours) and the loss of load probability of a power system. Therefore DG tends to increase the reliability of an electricity network. Table II compares DG and CG networks based on the resiliency indices.

TABLE II
RECOMMENDATIONS OF FACTORS AFFECTING RESILIENCY IN COMBINED CG AND DG

Factors	**DG**	**CG**	**Recommendations**
Reliability	High reliability but has power output limitation	High with more output power	Combined DG and CG with more DG in the grid
Stability	Better stability	Good stability however more difficult to return to a stable state after a system disruption	Combined DG and CG with more CG in the grid
Faults in the grid	Less severe impact	Severe impact	Combined DG and CG with more DG in the grid
Extreme unforeseen events	Reduced vulnerability	Vulnerable	Combined DG and CG with more DG in the grid

C. Sustainability in CG and DG Systems

Sustainability of a power system network [9] is the capacity of the power grid to withstand load requirements and meet the power consumer's need. Previous evaluations of CG and DG show that more installation capacity is required for a CG than a DG since the CG has more power demand on it than a DG. But considering the cost of installation and ease of resource availability, DG systems could very well serve as a better option to meeting the increasing needs of consumers. Sustainability means the capability of critical infrastructures to persist functions or services in a longer term.

The use of DG has gained significance attention in a liberalized electricity market. It is expected to make a particular contribution to climate protection. A metric to measure Sustainability $T(S_r)$ be defined as:

$$T(S_r) = P(S_r)\big(f(S_r)\big)^{-1} = [\sum_{j\in S_r}^{n} P_j][\sum_{j\in S_r}^{n} P_j \sum_{j\notin S_r}^{n} \lambda_{jr}]^{-1} \quad (4)$$

This could be used to measure the level of sustainability of either a DG or CG networks where contingency *j* at certain load level is characterized with probability *pj* and transition rate λ_{jr} is from and to other system states *j*, *r*. There are several and important drivers that aim at mitigating fossil fuel dependency thereby substituting these fuels for more sustainable sources of energy. (4) Defines the optimal combination of CG/DG to meet demands under assortments of power and seasons of the environment.

1) Sustainability and Development Through DG

New demand for reduction in the electricity generation in environmentally sustainable manner has resulted in the increase in DG only and CG/DG power networks. Sustainable energy has two key components: renewable energy and energy efficiency. Sustainability in a DG system would thereby aim at addressing the following:

- Energy consumption reduction
- Reduction of sources of energy waste
- Minimization of energy production pollution
- Minimization of life-cycle costs of renewable energy resources
- Sustainability in CG and DG Systems

2) Scenarios for GD/CG Comparison

The following four scenarios can be used as comparison basis for the sustainability requirements from co-optimizing CG and DG. These factors can be used as criteria in selecting the mixture of DG and CG integration for developing sustainable electric supply chain and include:

- Environmental protection: concerns climate change and conservation resources. How each of this will contribute to electric power system sustainability will be compared.
- Health and safety in environment: this is an aggregate comparison to be undertaken depending on the location and type of technology use for DG.
- Security of Supply: here we need to look at the medium to long term availability or the diversity of fuel options from producing the power; consideration of low cost of availability reduction nor loss of grid or plant and also adaptability of DG to different fuel and resources.
- Economic impact: leads to job creation increase in production of services, innovation, flexibility and increase knowledge.

On a local basis there are opportunities for electric utilities to use DG to reduce peak loads, to provide ancillary services such as reactive power and voltage support, and to improve power quality with non-intermittent DG or DG/storage combinations. Using DG to meet these local system needs can add up to improvements in overall electric system sustainability.

D. Power Quality

In simple terms, power quality is the measure of voltage quality at the end user. If the voltage is proportionate with the generated voltage by a constant ratio, then the power quality is said to be better. However, if the end user's voltage fluctuates constantly while the generated voltage remains constant, the power quality for such a system is very poor and thus a need arises for the assessment of such power quality. Power quality in a power grid network needs proper assessment as reliability of the grid is also based on the level of power quality in the grid. Favorably, the DG networks supplies power consumers' electricity over a small region of operation. Such power qualities to be addressed include: voltage sag, voltage swells, switching surges and harmonics [9].

The inclusion of power quality study for assessing the role of DG and CG based on fundamental criteria (that include steady state voltage rise, voltage fluctuation, voltage dip, generator start-up and static voltage stability) could be used for the selection of best power grid topology that minimizes the cost of incorporation of DG, CG or both systems.

Recall that CG networks are over long distances as compared to DG networks. It therefore follows that a CG network system is more prone to voltage fluctuations, voltage dip, and instability when compared to a DG system designed to support the voltage. This, however, does not limit power quality challenges to a CG system. DG networks are efficient and can be used to address a grid power quality challenges by the incorporation of storage systems (e.g., flywheels and super-capacitors,) and equipment usable as a power conditioner.

E. Economic Issues Facing the Integration of Distributed Generation into a Centralized Generation Based System

- The cost of electricity generated from DG in most cases is higher than the ones form CG except when governmental subsidies apply. However, as technology advances some DG technologies will acquire grid parity.
- DG's distributed nature may require redesign of the electricity supply infrastructure to accommodate reverse power flow on the distribution system.

F. Technical Issues Facing the Integration of Distributed Generation into a Centralized Generation Based System

- Evolution of the electricity networks will be found in future distribution networks where automatic network reconfiguration schemes aimed at facilitating high penetration of DG while reducing systems down time due to faults.
- Fault levels will increase when the DG is installed.
- In a radial distribution system DG integration is capable of increasing the local voltage above the standard voltage.
- Network stability issues under fault conditions involve new system dynamics which may cause instability depending on the characteristics of the DG. If this occurs, appropriate control systems have to be included at a cost to overcome the instabilities

Other unrelated impediments that may affect DG installation include: relatively small size, high cost (federal and local subsidy for renewable generation may not be sustained), internment power production, power quality issues, etc.

IV. CONCLUSION

This paper compared the merits and costs associated with co-optimizing DG and CG in a future electric grid. This comparison was based on different assessment indices such as technology, cost, and maintenance. To provide answers to the posed objectives of this paper, it becomes important to evaluate the economics of DG and CG technologies. Other indices (such as cost of maintenance, economies of scale, resiliency, sustainability, and ability to withstand growing demand) are also discussed in this paper. Table 3, shows a comparative analysis for valuing DG and CG for meeting different load demands in the future grid.

Furthermore, indices to evaluate the response of DG and CG to different catastrophic or extreme events which lead to system vulnerability and instability were also discussed. A matrix of performance indices is proposed to include resiliency, stability, and reliability to measure the performance of grid-connected only CG systems, only DG systems or a combination of CG/DG systems. The combined CG and DG network in terms of sustainability, resiliency, economics of scale, and cost are proposed to be used in determining the optimal combination of DG and CG in the future grid. To this end, following our analysis in the paper, we propose a national roadmap to promote research and open forum discussion in addressing strategic activity in achieving a future development of co-optimization of CG/DG that leads to a future grid.

TABLE III
CG AND DG VALUES AND RECOMMENDATIONS

Value	**Distributed Generation**	**Centralized Generations**	**Recommendation for CG and DG options**
Continuous Power	Capacity to provide continuous Power and characterized by: -high electric efficiency -low emission	Capacity for continuous operation and characterized by: -low electric efficiency as a result of high losses at the transmission system -high emissions	For continuous power production, increase DG penetration is required to reduce emission of greenhouse gas and increase efficiency
Cost	Low variable cost Low maintenance costs	High variable cost, high maintenance cost	With respect to cost, DG based networks is preferable
Peaking Output power	Operated between 30 – 3000hrs/year to reduce overall electricity costs.	It is operated intermittently at various peak powers.	Combined CG and DG
Resiliency	More resilient since it serves low power demand continuously		Combined CG and DG
Sustain-ability	Greater utilization of sustainable sources of power	Sources of power results in less sustainability	More of DG is preferable

V. FUTURE WORK

Distributed Generation can be depicted as an attractive energy resource in the near future or long-term when the energy supply and capacity challenges becomes even more critical. To develop a framework for development of CG/DG, a national research agenda for the development of the Infrastructure for the Future Electric Grid will include:

- Determination of costs and tradeoffs between CG and DG with respect to control costs, life cycle analysis, protection and maintenance for determining economies of scale
- Development of resiliency, and sustainability metrics for power systems planning and operation which will help to evaluate stability margin, demand response, and reliability issues.
- Determination of value added CG and DG incentives in terms of performance of the future grid under uncertainty, taking into consideration renewable energy, storage, plug-in cars, ramping, price response, and demand management of the grid
- Develop a new research thrust in areas of cost benefit analysis and incentives for owners of clean DG technologies and the reduced health risks to society
- Develop better and faster algorithms which include adaptive predictive modeling with the capability of handling grid resiliency and sustainability.
- Impact studies and analysis, which include reliability, stability, network congestion,
- Land use effects: The value of reducing "foot-print" or space needed by generation, transmission and distribution infrastructures.
- Consumer options for participation in demand response
- Ancillary services. The value of providing spinning reserve, regulation, or other ancillary services with respect to the cost-benefit analysis study.

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VII. BIOGRAPHIES

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The Need for a Hierarchichal Privacy-Aware Information-Sharing Framework for Metering in Smart Grids

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***Abstract*--Information and communication technologies (ICT) can improve the sustainability of activities in the physical world and lower greenhouse gas emissions in other sectors, notably electric power generation and distribution. Advanced communications and networking technologies are expected to play a vital role in future power systems and smart grid infrastructures. They will provide a two-way information flow to enable more efficient monitoring, control, and optimization of different grid functionalities, including two-way energy flow between smart power devices. This paper explores the need for the design of a hierarchical information-sharing framework that manages the information flow across different data collection points in the end-to-end electric power distribution system. The two research challenges described in leveraging ICT for delivering energy are: (i) managing massive amounts of data that are collected from data generating sources such as smart meters and distributed energy resources through the communications infrastructure, and (ii) preserving customer privacy while at the same time allowing frequent-enough data collection of energy use by grid operators for operational planning.**

I. Introduction

The need for improved communications at the power distribution level takes on greater importance with the introduction of the Smart Grid approach. Title XIII of the Energy Independent and Security Act 2007 [4] requires improved operation of distribution systems that includes development and incorporation of demand-side and energy-efficiency resources, deployment of real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices, and provisions for timely information and control options to consumers, to name a few. These developments and deployments require additional capabilities of the grid, especially a better communication infrastructure beyond the supervisory control and data acquisition (SCADA) level communication.

The critical requirement for advancement in the distribution system is real time information sharing and automation. By improving the communication infrastructure, a vital ingredient for the Smart Grid, a more reliable approach could be taken to better manage assets. In addition to asset and outage management tasks, communication will also aid in better energy management and tariff-related information. Deployment of smart distribution systems necessitates proper identification of power system requirements and integrating suitable communication and control infrastructure. The information communication and control layer of the smart grid brings about numerous advances, including the empowerment of customers to actively participate in the maintenance of the supply-demand balance around the clock and the resulting reliability improvement in electricity service.

Advanced Metering Infrastructure (AMI) initiatives are a popular tool to incorporate the changes for modernizing the electricity grid, reduce peak loads, and meet energy-efficiency targets. With the introduction of AMI technology, two-way communication between a smart meter (SM) and the control center, as well as between the smart meter and customer loads can be facilitated for demand response, dynamic pricing, system monitoring, cold load pick-up, and greenhouse gas-emission mitigation [5]. AMI uses technology to capture and transmit energy use to a concentration point on an hourly or sub-hourly basis in contrast to standard meters that provide a daily energy usage total and a cumulative monthly bill. This application requires bidirectional communication: control commands from the control center of the utility to smart meters, and load profiles and logs from smart meters to the control center.

Though current AMI deployments are capable of data collection by employing various technologies, they have not been backed up by an effective framework to share data and information. The design of an information-sharing framework for the AMI and associated home area networks (HANs) to meet smart grid requirements is still an open research problem, with both further encumbered due to the stringent requirement of ensuring customer privacy. On one hand, utilities need to collect low-level customer data to improve operational planning and control. On the other hand, customers have privacy preferences which need to be met to encourage greater smart meter adoption rates that in turn benefits utilities. An ideal information-sharing framework will allow a customizable level of data collection to meet specific

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customer privacy requirements within the context of the AMI.

One of the challenges to the AMI application scenario will be handling the massive amount of data that is expected to be collected from smart meters and sent through the communication backhaul to the utility. By current standards, each smart meter sends a few kilobytes of data every 15 minutes to a smart meter [6],[7]. When this is scaled up to large numbers, many existing communication architectures will either find it difficult to handle the data traffic due to limited bandwidth, or incur costs for provisioning greater network capacities. This challenge will be greater at higher levels of the data collection tree where packets from thousands of sources will aggregate [8]. In future, new applications may require data to be collected at a finer granularity adding to the challenge.

II. Solving Problems of Grid Integration

The design of a hierarchical information-sharing framework that manages the information flow across different data generation/collection points in the end-to-end power distribution system is an open problem. These data collection/generation points would span the grid operator control center all the way down to individual data generators such as customer meters and distributed energy generation sources. Developing appropriate mechanisms to manage the information flow will involve answering the following three high-level questions after identifying prior work done related to each question.

1. *How does the information flow across different stakeholders look like? What information is required by grid operators at each level of the data collection hierarchy from an operational standpoint?*

Prior Work: Figure 1 shows the traditional power system and the envisioned smart grid from the power delivery viewpoint. From the figure, it can be seen that many more changes are needed at the power distribution level than exist currently. These changes would support the introduction of photo-voltaic solar panels (PVs), electric vehicles, AMI, and distributed wind generation. These application scenarios have communication needs with latencies varying from milli-seconds to hours, with many requiring bi-directional flow back and forth with grid operators.

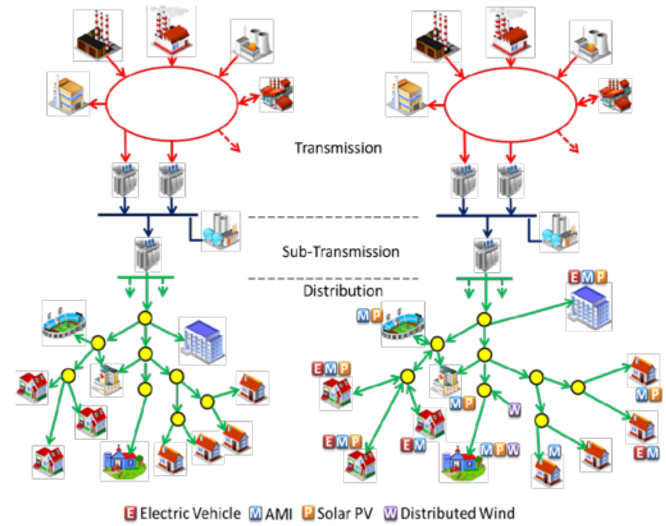
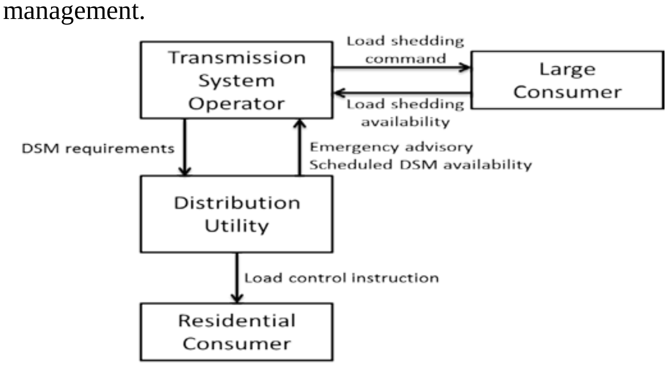
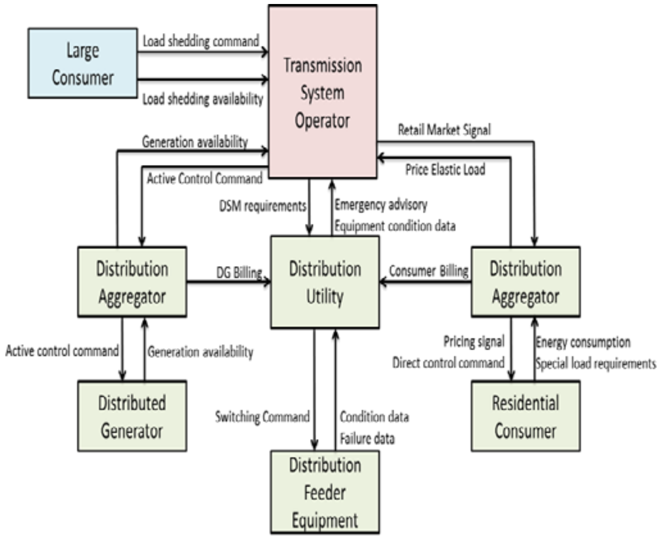


Fig. 1. Transformation of current electric power grid to future grid with the addition of new data generators and their expected information flows

Figure 2 (a) and (b) show how the current and future grid is expected to look like in terms of information flow for demand-side management. In the conventional power system that is in operation today, few large consumers opt into a load shedding program. During an abnormal condition, the power system operators at the transmission level would curtail some load from these large consumers. Some of the distribution grid operators are participating in demand side management (DSM) using a direct control approach where the grid operator would have an agreement with consumers to manage their load, especially air conditioning load, during peak hours. In most cases these distribution consumers are collectively controlled by only a single command which is not desirable. The unidirectional control is mainly due to a lack of adequate communication infrastructure. There has been significant interest in developing a new information sharing approach to improve the feedback based control for demand side management.



(a) Current demand-side management (DSM) information flow



(b) Futuristic smart distribution system information sharing model.

Fig. 2. Current and expected future information flow for the demand side management application scenario

A futuristic approach to the information sharing mechanism developed by the investigators based on the available literature [9], [10], [11], [12], and [13] is presented in Figure 2(b). In the new paradigm it is expected that the management of large consumer loads would be similar to the current model except that communication requirements at the power distribution level would be much greater to enable a smarter grid. Based on Figure 2(b) it could be seen that more bidirectional communication infrastructure is necessary at different levels. For example: (i) a new decision making level is necessary to minimize the distributed generators needed, (ii) distributed generators need to share their availability, and receive required control commands to minimize power losses and maximize reliability, (iii) availability of price-elastic loads, and special loads such as electric vehicles when charging, should be masked and shared with the such entities to manage the privacy of the consumer. Furthermore, the consumer should be informed about demand side management commands, and (iv) to improve system reliability and security, the distribution equipment health data should be shared with grid operators periodically and any abnormality should be shared immediately. It is expected that such capabilities would minimize energy waste by managing energy utilization. As these capabilities also have the potential increase integration of renewable energy sources, grid operators would be able to increasingly meet environmental goals.

2. *What is the best approach to build an information-sharing framework to collect, propagate, and store information at the power distribution level of smart grids?*

Prior Work: Many types of communication techniques, with different levels of maturity, are being employed in emerging deployments by grid operators at the power distribution level around the United States, Europe, and Asia (e.g., for the U.S. consult [14]). These deployments embody various communication solutions, but only a few have complete end-to-end bi-directional information and control capabilities. This is a nascent field with little published research on communication infrastructure design at the power-distribution level. The work in [15], [16], [17], and [18] all consider different communication backhaul architectures and technologies to meet communication needs for smart grids at the electric power distribution level. However, it is not yet clear what technology, or combination of technologies, can effectively meet the requirements for large-scale smart grid undertaking at the distribution level where greater automation and consumer participation in energy delivery is sought.

In addition to the lack of a comparative evaluation of possible communication technologies for consumer participation, there is the looming issue of how to communicate and handle consumer data collected by electric grid operators and manage limited communication network resources [19], while at the same time meeting consumer security and privacy goals. There is reasonable consensus on using ZigBee-based star topologies in HANs [20] and [21], and ZigBee- or Wi-Fi-based mesh topologies to collect and aggregate data at concentrators [22]. However, the technologies and topologies to be used for the backhaul and how to aggregate arriving packets at data concentrators to minimize communication infrastructure overload is still an open problem. In addition, the manner in which consumer data is communicated and collected has security and privacy implications that must be considered. Thus, building such an information-sharing infrastructure would require handling the two most important aspects of data volume and customer privacy jointly, not independently as is common in current efforts.

3. *How can we quantify customer privacy in smart grids? How can information privacy be preserved by regulating the amount of information available across different levels of the data collection hierarchy?*

Prior Work: In addition to efficient communication, storage and aggregation mechanisms, the privacy of customer usage data and patterns is of critical importance in the upcoming smart meter paradigm. As a result, the privacy issues in AMI and similar applications that interface with consumers has started to receive some attention from researchers but significant open problems in this direction are yet to be addressed. [23] provide a comprehensive overview of the Smart Grid technology and the various privacy risks posed by the Smart Grid and AMI. [24] identify the various privacy threats in smart metering technology and analyze their impact on society by outlining the details of the smart meter technology, the information produced by it and the various stake holders in this technology. [25] identify the specific privacy issues related to accurate billing and data aggregation in smart meter systems. Some of the recent works [26] and [27] have also shown the feasibility of serious security and privacy intrusions by using simple off-the-shelf technology, which further reinforces the need for building a secure and privacy-preserving data-sharing framework in smart grid systems.

As shown in Figure 2(b), the future smart grid is envisioned as an information system (or more precisely, an information-based energy production and distribution system) where system data or information will be generated, aggregated and shared at various levels. As a result, different privacy concerns arise at different levels. For example, at the customer data generation level, customers are concerned with unauthorized disclosure of their personal usage information with malicious eavesdroppers or third-party service providers [26]. Similarly at the distribution aggregation level, the biggest concern is to aggregate data in a useful (to the grid operator), yet privacy-preserving (from the customer standpoint) fashion. There has been some progress on privacy-preserving data aggregation in smart-grids. For example, [28] use cryptographic building blocks such as signature schemes, commitment schemes and zero-knowledge proofs to construct efficient and verifiable aggregation functions such as billing, which are done at the customer end. [29] propose a set of interactive protocols for privacy-preserving aggregation and comparison of fine-grained meter readings. In another research effort, [30] propose a set of cryptographic protocols for computing aggregate statistics for a set of users (without revealing their individual readings) by using homomorphic properties of cryptographic encryption functions. As opposed to the previous effort, this work assumes the presence of a Trusted Third Party (TTP). Similarly, [31] propose protocols for anonymous sharing of energy usage information with the service providers using a TTP. Despite these advances, there is a major shortcoming in existing aggregation approaches. These approaches do not treat smart meter data as customized time series data and (implicitly) assume that all consumers share data for aggregation at fixed and equal data sharing intervals. This is obviously not a practical assumption as consumers could have different sensitivities to privacy and as a result may share data with different frequencies. For example, a privacy-averse user would share data at 15 minute intervals, whereas a privacy sensitive user would only share data at 1 hour intervals. Any aggregation done without taking into consideration such data-sharing sensitivities would obviously produce incorrect or unexpected results for the overall aggregation function. Thus, the need of the hour is to develop accurate data aggregation mechanisms and privacy-sensitive data regulation mechanisms at various levels, which are not only privacy-preserving (i.e., it is difficult to guess individual consumer information from the aggregated function), but are also adaptive to the different privacy requirements of the consumer.

In order to better understand the privacy requirements of the consumer (or other stake-holders at different levels), we require formal and well-defined metrics and measures for privacy. There has been limited progress in this direction. [32] propose a game-based model for measuring the privacy-leakage in a smart meter system by using a TTP. Recently Sankar et al. [33] introduced a theoretical measure of consumer privacy by relying on the classic measures of information, namely entropy and mutual information. Although these measures of privacy are very useful, they are very general and do not capture specific privacy leakages at specific levels at which information is exchanged and aggregated. The privacy measure of a particular stakeholder at a specific level (as shown in Figure 1) would depend on the nature and extent to which information is aggregated and exchanged at that level, the generators and consumers of the data at that level and the nature and extent of the information that percolates beyond that level. General privacy frameworks, such as the one proposed in [33], are not very useful for capturing all the privacy leakages in a multi-level smart meter information system shown in Figure Figure 1 and we need to design more specific measures and mechanisms.

III. Future Research Needs

The <u>key research questions</u> that need to be addressed in the near future are the following:

<u>Data Volume</u>

1. What data should be collected from consumers to aid operational planning?
2. What is the best communications architecture to collect this data from consumers?
3. Where should this data be stored?

<u>Customer Privacy</u>

1. How can we quantify customer privacy in smart grids?
2. How can we make optimal information-sharing decisions based on this quantification?

<u>Overall</u>

1. How can we balance the data-collection needs of the utility with preserving customer privacy?
2. What would be the best way from a communication infrastructure perspective to collect, handle, and store data with customer privacy and information security in mind?

An information-sharing framework is needed for commonly envisioned smart grid applications of the future. This framework must dynamically transform data flowing upstream based on available network capacity) at each level of the data gathering tree while preserving the information that grid operators need and at the same time controlling privacy leaks. Such a design could formally involve solving the operator utility-consumer privacy tradeoff shown in Figure 3 to determine the level of information that will have to be collected to maximize grid operator benefits for a specific consumer privacy constraint. Subsequently, the information flow upstream to the grid operator can then be optimized using multi-level data aggregation/concentration schemes.

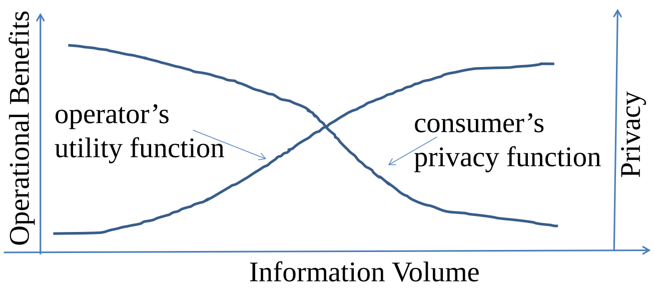


Fig. 3. The fundamental vision outlined in this paper is to design a hierarchical information-sharing entails (i) mapping information volume to consumer privacy (consumer privacy function curve), and (iii) studying the tradeoffs between grid operator utility and consumer privacy in conjunction with problem of efficient management of information volume through the communication infrastructure.

IV. Conclusions

This paper discusses the fundamental questions that need to be answered in designing an information-sharing framework that manages the flow of information from various data generation sources to higher levels of the hierarchical data collection tree. Such a framework will address the challenges of managing data volume in smart grids while balancing the need to ensure consumer privacy in moving from the current grid scenario to a future smarter grid. The design of such an information-sharing framework will also allow for greater efficiencies for grid operators in monitoring and control (including power theft) that should reduce overall energy use. Additionally, a long-term outcome will be to improve smart meter adoption rates by improving information security and alleviating consumer privacy concerns. Increased smart meter adoption rates will hasten the process of realizing AMI benefits and increased efficiencies. Such efficiencies result in reduced need for electricity generation, or better capability for demand side management that can work in conjunction with renewable integration (by helping deal with variability) to reduce environmental impacts of energy use.

V. Acknowledgment

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VII. BIOGRAPHIES

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Computation and Information Hierarchy for a Future Grid

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***Abstract*--Computation and information architecture of a future grid is considered. On computation architecture for smart grids, challenges and opportunities of having cloud computing architecture for the scalable, consistent, and secure operations of smart grids are examined. On information hierarchy, issues on how information should be partitioned in time and space are examined. The temporal characteristics of information hierarchy are investigated in the context of dynamic scheduling with deadline requirements. The spatial characteristics of information hierarchy are investigated by considering spatially distributed location real-time prices. Effects of data quality on location real-time prices and market dynamics are considered.**

I. Introduction

The electric grid in the United States has evolved over the past century from a series of small independent community-based systems to one of the largest and most complex cyber-physical systems today. The grid consists of tens of thousands of generators and substations, linked by transmission and distribution networks. The system state is estimated continuously using remotely collected data, and power delivery is orchestrated by sophisticated decision and computation processes.

The electricity markets are tied intimately to the operation of the grid. Despite practical challenges of serving electricity in real time to a large geographical area, the supply of electricity has been mostly reliable with a few well-publicized exceptions of regional blackouts.

The established conditions that made the electric grid an engineering marvel are being challenged by major changes, chief among these being the global effort of mitigating climate change by reducing carbon emissions. The U.S. government has set a target of reducing the national emissions of greenhouse gases by 80% from the current level by the year 2050. Within the United States, the national goal of achieving energy independence also calls for reducing imported oil significantly.

Achieving a reduction of fossil fuel at this magnitude requires a combination of integrating renewable energy, developing distributed energy sources and control capabilities, electrification of the transportation, and much improved energy efficiency for buildings and appliances. Transformative (and potentially disruptive) changes to the current structure of the energy industry may be necessary. Critical technological innovations are required.

The existing power grid is large and complex and its functionalities may have to be expanded significantly due to the needs of greater integration of renewable sources, demand-side participation, and the prolific use of web-based information technology for personal energy management. The current grid has limited observability in space and time, but this situation is being changed by the deployment of Phasor Measurement Units (PMUs), smart meters at home, smart sensors in buildings, and smart devices in new generations of green appliances.

Today's grid is based on a private computation and networking infrastructure. The development of future grid will be shaped by the "big data" information technology. With greater deployments of smart meters, PMUs and other new sensing devices, we will no longer face the problem of lack of information; the amount of available information will likely overwhelm our current ability to store, transport, and process information. This calls for a careful examination whether existing information architecture scales well for the envisioned smart grid, both economically and technologically.

A back-of-the-envelope calculation by Birman [1] serves to illuminate the potential need of a new computation and information architecture. It is estimated that a fully deployed PMU infrastructure may have the aggregate data transmission rate of approximately 15 Gbytes/second, beyond the full capacity of a state of the art optical network link.

Perhaps even greater impacts of big data come from communities and individual consumers who are increasingly tied to the information fabric of our society. The proliferation of mobile personal devices makes it possible for consumers to participate actively in *personal energy management,* creating new dynamic interactions between generation and consumption.

For example, mobile apps have already been developed for home energy management that interacts with internet services such as weather forecasting. Such apps can easily incorporate personal lifestyle preferences, real-time pricing signals, traffic information for scheduling the charging of electric vehicles, and consumption profile of local communities. Much of the computation and storage needs that serve the consumer are in a public infrastructure and will likely in the "cloud" in the future.

While it is easy to foresee changes in today's mostly centralized energy management paradigm, it is not unreasonable to draw a parallel with the evolutionary path of the computer industry, from centralized mainframe computing for large organizations to personal computing for individuals;

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from computing at offices and homes to mobile and embedded computing; from high performance parallel computing to cloud computing. Essential characteristics of this evolution are the personalization and localization of computing and the ubiquitous presence of networking. It is not difficult to argue that these same characteristics are present in the energy system, and they will have impacts on the development of a future grid.

It has been argued that [1] building a private network exclusively used for the future grid may not be an economically viable option; leveraging existing public investment in computation and networking infrastructure such as cloud computing and future internet technologies will be inevitable. Thus developing an appropriate computation and information hierarchy is an essential step toward realizing a reliable, efficient, and smart grid.

II. Cloud Architecture for Smart Grids

We discuss in this section merits of developing a cloud computing architecture for computation and operation needs of a future grid. It may be argued that cloud computing has the greatest potential to be the information and computation foundation for a future grid [1], [2], and the cloud is a unifying architecture for not only independent generators, ISOs/RTOs2, and local utilities but also consumers and communities on social networks.

A fundamental limiting factor for efficient and reliable operation of today's power grid is the lack of computation power. To this end, cloud computing provides a scalable and economic solution. The current SCADA systems and control centers relies on dedicated computation based on the architecture of high performance computing (HPC), which is limitted by the so-called checkpoint barrier [3]. In particular, because computation nodes for HPC may fail, check points are needed to ensure continual execution during failures. As the number of computation nodes increases for larger and more complex SCADA operations, the number of required check points increases dramatically, which becomes a fundamental barrier to large scale computation.

The cloud architectures, in contrasts, are supported by multiple data centers, each having a large number of simple and inexpensive servers. Despite that nodes and storage may fail, the redundancy and distributed nature of the cloud and advances from coding and information theory in distributed storage [4]–[6] make cloud architecture more reliable for smart grid operations and with greater computation speed and elasticity.

There have been growing activities on the use of cloud architecture for smart grid applications. See, e.g., [1], [7], [8]. Although the economy of scale favors a cloud architecture, cloud computing was not and has not been designed for power grid operations. Here we outline a few important challenges that must be addressed should cloud architecture become the computation and information backbone for smart grids.

A. Consistency, Time Criticality, and Scalability

The information and computation infrastructure for a future grid need to be available, responsive, fault tolerant, and resilience to attacks. Data essential for operational decisions should be consistent in the sense that the asynchronous arrival of information and updates at data centers should not lead to inconsistent decisions. This last property is especially important because the grid covers a large geographical area, and distributed data collection and storage may lead to discrepancies.

Data consistency and real-time guarantees are known to be at odds in distributed systems. What makes today's cloud architecture scalable is the notion of *weak consistency*, which does not enforce all data at different servers have the same level of freshness. The outcome of a search at one location may actually be somewhat different from that obtained at a different location. Nonetheless, for many web applications, "pretty good answers" are considered good enough, and weak consistency is deemed adequate. For real-time operation of the grid, however, weak consistency is insufficient; a much stronger guarantee for consistency is necessary.

There is a critical need to characterize fundamental tradeoffs among consistency, time criticality, and scalability. In [9], Brewer conjectured that that *consistency, availability, and partition tolerance (CAP)* cannot be satisfied simultaneously. Gilbert and Lynch later introduced a formal model and established a set of impossibility results [10]. The models considered in [10] are specific asynchronous models for read-write operations uncommon in grid operations.

The strict notion of CAP should perhaps be replaced by a more practically significant measure. To this end, it is useful to introduce tolerance levels in the three CAP attributes, replacing strict CAP by a notion of (1-e)-CAP. If one is willing to scale back strict consistency by probabilistic consistency, *e.g.*, achieving consistency with probability (1-e), replacing anytime availability to a more realistic measure of availability with high probability, and change partition tolerance by a weaker notion similar to that of N-1 contingency requirements, the problem of establishing that CAP cannot be achieved simultaneously is changed to one of characterizing the degree of achievable compromises among the CAP attributes.

B. Reliability, Security, and Trustworthiness

Today's cloud technology does not provide the level of reliability necessary for real-time operations. Data inconsistency and other anomalies due to data center and network outages may have detrimental effects on the reliability of the future grid. The increasing reliance on cyber-infrastructure to manage complex grids comes also with the risk of cyber-attacks by adversaries around the globe. If the future grid is to be managed by a combination of public and private cloud platforms, the risk of attacks will only increase.

Existing cloud computing platforms have weak security and privacy guarantees, which makes them vulnerable to internal and external attacks. The notion of "trustworthiness" goes beyond security. Because data are replicated in the cloud, and it is impractical to refresh them at an arbitrarily fast rate, it is possible that outdated data are used in critical decisions.

A natural approach to reliability and consistency is introducing redundancy in the cloud system. A naive solution is to duplicate storage units so that, in events of disk failures, essential data are not lost. Such a solution, however, is flawed because duplicating data necessarily increases data traffic and the chance of data inconsistency.

A more promising approach is to introduce redundancy in a more intelligently. The idea of coded storage [11] and more recent development of network coding techniques for distributed storage [5], [6] provide possibilities of achieving tradeoffs among reliability, efficiency, and security. As an application of error control techniques in communications to data center storage, sophisticated error detection and correction techniques are being developed by taking into account the need of frequent updates, possibilities of disk failure, and potentially malicious actions [12]. These ideas open new avenues toward cloud architecture suitable for real-time and secure operations in a future grid.

C. Estimation and Control in the Cloud

The "state" of the power grid is defined by the voltage phasors at all buses. The state variable captures the operating condition of the grid and contains sufficient statistics for operational decisions. Prior to the advent of PMU technology, state variables cannot be measured directly, and states have been estimated from data collected by the SCADA system. State estimation is implemented in all control centers based largely on the original ideas of Schweppe [13]. The deployment of PMUs greatly enhances the quality and resolution of state estimates [14]–[16]. With faster and synchronized sampling, state estimation will play a greater role in real time operation and control of the future grid.

What happens when state estimation is executed on a cloud platform? What are the impacts of conflicting, bad, or missing samples on state estimation and operations using state estimates as input of operational decisions? How trustworthy are state estimates on a cloud system? Works on estimation and control with intermittent packet drops are particularly relevant. (see [17], [18] and references therein) Information theory and coding techniques have also been considered in dealing with imperfections introduced when data sensor data are communicated to the control center [19].

Classical state estimation incorporates practical bad data detection as a way to eliminate outliers or mistakes in data collection [20]–[22]. These techniques, however, are not effective in dealing with complex situations arising in a cloud platform and the possibilities of external or internal (Byzantine) attacks. There have been recent efforts in characterizing effects of bad or malicious data on state estimation and on real-time location marginal price (LMP). See [23]–[25].

III. Information Hierarchy In Time

To achieve large scale integration from wind and solar sources that are stochastic and time varying, existing modus operandi based on day-ahead planning and worst case contingencies may have to be changed. Because uncertainty increases with planning horizon, day ahead forecast o generation level from renewable sources can at best be used to characterize the ensemble behavior. If a high percentage of renewable generation is integrated into a future grid, operation decisions have to be made with a shorter time horizon such that they can be made more adaptive to changing operating conditions. To this end, it is necessary to view randomness in supply and demand not as minor perturbations from som deterministic norm but as fundamental characteristics of energy management in a future grid.

Information hierarchy in time addresses the problem of what kind of information is required and by what time decisions have to be made. The information structure for real-time decisions can be modeled as a nested sequence of observed events—an information filtration. Conditioned on the sequential arrivals of information, the control center takes actions based on cost/profit considerations, constraints, contingencies, and operation deadlines. The general framework for these types of problems is a multistage decision process.

We present below two types of scheduling problems that are particularly relevant; one follows a robust formulation by considering worst case scenarios, the other a stochastic formulation with average performance measure. In both cases, the decision problems involve explicitly deadline constraints.

A. Real-Time Scheduling with Deadlines

Deadline scheduling is a classical and fundamental problem where jobs arrive at a control center with different processing needs and deadlines of completion. Such problems arise naturally in home energy management where a controller schedules loads with different characteristics, some with firm deadlines of completion and others with deadlines on the starting time.

For example, a residential consumer may require that an electric vehicle be charged by 7 Am or a washer/dryer be start no later than 8 PM. Yet other jobs may have deadlines that are not firm, deadlines that may be specified in a probabilistic setting in terms of average time of completion or the probability of completion.

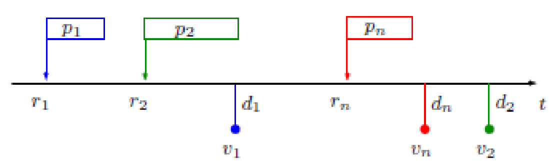

Fig. 1. Arrivals of jobs with deadlines

In a generic form, a job $J = (r, p, d, v)$ is defined by a quadruple: the arrival time r, the required processing time p, the deadline d, and v the utility of completing the job. Fig. 1 illustrates a particular scenario of the arrivals of jobs with deadlines. The problem of deadline scheduling is to determine, at any time, which jobs are to be served subject to certain processing capacity constraints.

Deadline problems can be formulated in a deterministic or a stochastic setting. The latter often requires knowledge of joint probability distributions of arrival time, job sizes, processing time, and deadlines. Such prior knowledge, however, may be difficult to have in practice. An alternative is the framework of *competitive scheduling* based on a deterministic formulation. In such a setting, all variables are modeled as deterministic quantities, and the performance of any online scheduling algorithm can be compared with the optimal offline algorithm.

The *competitive ratio* $C(\pi)$ of an online policy π is defined as the ratio of the reward accrued by the online policy π over that by the optimal offline policy for the worst possible job arrival scenarios. The optimal online policy is then defined as the one that achieves the supremum of competitive ratio among all online policies. Scheduling under deadlines are well known challenging problems with many new applications. It was shown by Karp [26] that optimal off scheduling for problem of deadline scheduling is NP-complete. Thus no polynomial time solution is known to exist. On the other hand, simple online scheduling algorithms that achieve the best competitive ratio do exist. For example, the earliest deadline first (EDF) algorithm works on the job with the earliest deadline, and it switches to a newly arrived job if the new arrival has an earlier deadline. It is known that such a simple scheduling algorithm is optimal when the traffic load is light. See in particular the seminal work of Liu and Layland [27], the work of Mok [28], Locke [29], recent applications in scheduling jobs for cloud systems [30] and the large scale EV charging [31]

As an application, consider the problem of charging electric vehicles (EVs) at a parking lot or a garage. The customers arrive with different charging needs and required deadlines for completion. Suppose that the chargers are powered by a mixed of (inexpensive and locally generated) renewable source and expensive electricity purchased from the grid. Given varying level of available renewable sources, an operator wishes to have a scheduling policy that maximizes its operating profit by optimizing its charging schedule.

The energy management system for the large scale charging of EVs faces multiple challenges. The service provider has to deal with uncertainties associate with the arrivals of jobs (demand) as well uncertainties associated with the varying price of electricity. Given a fixed pricing scheme, the service provider optimizes its profit by exploiting flexibilities associated with specified deadlines.

The problem of pricing EV charging services is nontrivial. For instance, it is reasonable to charge a consumer a higher price when a submitted job has a tight deadline. Therefore, a service differentiated pricing may be appropriate, which makes jobs with tight deadlines higher priority and more profitable. On the other hand, a consumer may respond to pricing schemes by either reducing consumption or turn to competing service providers. A main challenge is to optimize jointly deadline scheduling and pricing in a competitive market.

B. Multistage Decision and Risk-Limiting Dispatch

The objective of unit commitment and economic dispatch in the electric power system is to schedule generators and reserves to meet the demand in the presence of uncertainties and random contingencies. The decision process in the current power system is a two-stage optimization involving day ahead planning and real-time adjustments. The decisions at the two stages are only loosely coupled. When there is a high degree of uncertainty, reliability considerations based on worst case scenarios lead to over provision and inefficiency. When the generation portfolio includes a high percentage of renewable sources, the cost of over-provision of reserve offsets the benefits of renewable integration.

The key idea of risk limiting dispatch articulated by Varaiya, Wu, and Bialek [32] is to exploit the fact that uncertainties associated with random generation decreases as the decision horizon reduces. To take advantage of real-time measurements that help to improve forecast accuracies, risk limiting dispatch reduces the decision horizon by increasing the number of stages in the stochastic optimization. As time gets closer to the scheduled actions, increasingly tighter limits on risks are imposed.

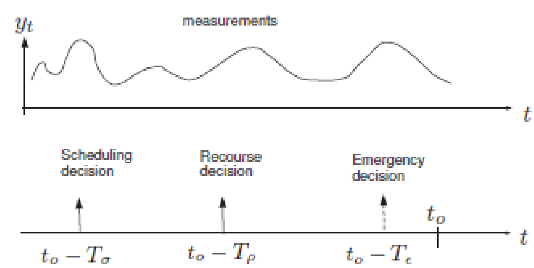

Fig 2. Decision epochs of risk limiting dispatch [32]

Figure 2 illustrates a sequence of decision epochs that influence the actual actions (power generated or consumed) at the decision deadline $t = t_o$. Three types of decisions are made based on available information from time 0 up to time t: the scheduling decision u_σ at to $t_o - T_\sigma$; the recourse decision $u\rho$ at to $t_o - T_\rho$, and the emergency decision (if necessary) $u\varrho$ taken at time $t - T_e$.

The formulation of such decision processes requires an abstraction of information and decision structure, reliability/ security constraints, and constrained optimizations. The underlying optimization in risk limited dispatch is nontrivial, but structured solutions may exist under certain conditions. See [33], [34].

IV. Information Hierarchy in Space

We discuss in this section spatial characteristics of information hierarchy. In this context, information hierarchy in space addresses the problem of collecting and disseminating information to a large geographical area and issues related to networking requirements, data resolution, and latency.

The real time location marginal price (RT-LMP) has been the main mechanism to settle day-ahead and real-time markets [35], [36]. If the cloud is to be a backbone for the computation and information management of the smart grid, the issue of data quality has to be addressed. We have already discussed earlier that the current cloud assumes merely weak data consistency. Furthermore, there are always possibilities that adversaries (potentially insiders of the energy industry) can covertly manipulate data to affect real time prices.

The impact of data inconsistency on RT-LMP is not well understood. In a recent work [37], [38] has shown that the manipulating data from unprotected meters can result in a significant change of RT-LMP [37]. Indeed, data attacks on one location can change significantly prices far away. Indeed, because the RT-LMP is a solution of a linear program from a linearized incremental optimal power flow, RT-LMPs are computed from vertices of certain polytope determined by congestion conditions of the network. Inconsistencies or data anomalies can result in the congestion pattern deviating from the reality, causing significantly changed RT-LMP values.

If demand response is one of the main characteristics of a future grid, one has to consider impacts of data quality on the volatility and stability of the electricity market.

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