# Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software

**Agenda**

**AD10-12-006**
**June 22 – 24, 2015**

**Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software (Docket No. AD10-12-006)**
Federal Energy Regulatory Commission, 888 First Street NE, Washington DC
**Draft Agenda (Abstracts Attached Below)**

Monday, June 22, 2015

| | |
|---|---|
| 8:30 AM | Introduction (Meeting Room 3M-2)<br>**Richard O'Neill**, Federal Energy Regulatory Commission (*Washington, District of Columbia*) |
| 9:00 AM | Session M1 (Meeting Room 3M-2)<br>**Computational and Design Needs in RTO Markets: A PJM Perspective**<br>Paul Sotkiewicz, PJM Interconnection, LLC (*Audubon, Pennsylvania*)<br>**Day-Ahead Market Clearing Software Performance Improvement**<br>Yonghong Chen, MISO (*Carmel, Indiana*)<br>Aaron Casto, MISO (*Carmel, Indiana*)<br>Xing Wang, Alstom (*Redmond, Washington*)<br>Jie Wan, Alstom (*Redmond, Washington*)<br>Fengyu Wang, MISO (*Carmel, Indiana*)<br>**SPP Security Constrained Unit Commitment Enhancement and Performance Improvement**<br>Jie Wan, Alstom Grid (*Redmond, Washington*)<br>Gary Cate, SPP (*Little Rock, Arkansas*)<br>David Gary, Alstom Grid (*Redmond, Washington*)<br>Xing Wang, Alstom Grid (*Redmond, Washington*) |
| 10:30 AM | Break |
| 10:45 AM | Session M2 (Meeting Room 3M-2)<br>**Convex Hull Pricing: Rigorous Analysis and Implementation Challenges**<br>Dane Schiro, ISO New England (*Holyoke, Massachusetts*)<br>Tongxin Zheng, ISO New England (*Holyoke, Massachusetts*)<br>Feng Zhao, ISO New England (*Holyoke, Massachusetts*)<br>Eugene Litvinov, ISO New England (*Holyoke, Massachusetts*)<br>**Price Enhancements for Real-Time and Day-Ahead Markets**<br>Congcong Wang, MISO (*Carmel, Indiana*)<br>Juan Li, MISO (*Carmel, Indiana*)<br>Dhiman Chatterjee, MISO (*Carmel, Indiana*)<br>Robert Merring, MISO (*Carmel, Indiana*)<br>**Approaches to Reduce Energy Uplift and PJM Experiences**<br>Ying Xiao, Alstom Grid (*Redmond, Washington*)<br>Paul Sotkiewicz, PJM Interconnection (*Valley Forge, Pennsylvania*) |
| 12:15 PM | Lunch |
| 1:30 PM | Session M3 (Meeting Room 3M-2)<br>**NYISO Retrospective Market Simulation Toolkit**<br>Charles Alonge, NYISO (*Rensselaer, New York*)<br>Tate Hoag, NYISO (*Rensselaer, New York*)<br>Jiaxiao Hu, NYISO (*Rensselaer, New York*)<br>Bruce Budris, NYISO (*Rensselaer, New York*)<br>Muhammad Marwali, NYISO (*Rensselaer, New York*)<br>**MISO Experiences with Congestion Management Enhancement**<br>Li Zhang, MISO (*Carmel, Indiana*)<br>Kevin Sherd, MISO (*Carmel, Indiana*)<br>Shu Xu, MISO (*Carmel, Indiana*)<br>Robert Merring, MISO (*Carmel, Indiana*)<br>Chuck Hansen, MISO (*Carmel, Indiana*)<br>**A Marginal Equivalent Algorithm and its Application in Coordinated Multi-Area Dispatch Problem**<br>Feng Zhao, ISO New England (*Holyoke, Massachusetts*)<br>Eugene Litvinov, ISO New England (*Holyoke, Massachusetts*) |
| 3:00 PM | Break |
| 3:15 PM | Session M4 (Meeting Room 3M-2)<br>**Day-Ahead Window Optimization**<br>Muhammad Marwali, NYISO (*Rensselaer, New York*)<br>Fred Adadjo, NYISO (*Rensselaer, New York*)<br>**Consider Natural Gas Pipeline Constraints in Electricity Market Operations**<br>Xing Wang, Alstom Grid (*Redmond, Washington*)<br>Tongxin Zheng, ISO New England (*Holyoke, Massachusetts*) |

| Monday, June 22, 2015 | |
|---|---|
| 4:15 PM | Break |
| 4:30 PM | Session M5 (Meeting Room 3M-2)<br>**Tackle Load and Interchange Uncertainties: PJM's Experiences**<br>Hong Chen, PJM Interconnection, LLC (*Audubon, Pennsylvania*)<br>**Voltage Stability Assessment Implementation in NYISO - Toward a Better Utilization of the Transmission Grid**<br>De Tran, NYISO (*Rensselaer, New York*)<br>Vladimir Brandwajn, ABB Inc. (*Santa Clara, California*) |
| 5:30 PM | Adjourn |

Tuesday, June 23, 2015

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|---|---|
| 8:15 AM | Arrive and welcome (Meeting Room 3M-2) |
| 8:30 AM | Session T1-A (Meeting Room 3M-2)<br>**Stochastic Optimization for Unit Commitment and Electricity Market Operation: A Review**<br>Zhi Zhou, Argonne National Laboratory (*Lemont, Illinois*)<br>Audun Botterud, Argonne National Laboratory (*Lemont, Illinois*)<br>**Two-Stage Stochastic Unit Commitment Models with Explicit Reliability Requirements through Conditional Value-at-Risk**<br>Andrew Liu, Purdue University (*West Lafayette, Indiana*)<br>Qipeng Zheng, University of Central Florida (*Orlando, Florida*)<br>Yuping Huang, University of Central Florida (*Orlando, Florida*)<br>**A Chance-constrained Unit Commitment Model for Power Systems with High Penetration of Renewable Energy**<br>Gabriela Martinez, Cornell University (*Ithaca, New York*)<br>Lindsay Anderson, Cornell University (*Ithaca, New York*)<br>**Stochastic Unit Commitment at Scale: Cost Savings Analysis for ISO-NE**<br>Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, New Mexico*)<br>David Woodruff, University of California Davis (*Davis, California*) |
| | Session T1-B (Meeting Room 3M-4)<br>**Near-Global Solutions of Nonlinear Power Optimization Problems: Theory, Numerical Algorithm, and Case Studies**<br>Javad Lavaei, Columbia University (*New York, New York*)<br>Ramtin Madani, Columbia University (*New York, New York*)<br>Abdulrahman Kalbat, Columbia University (*New York, New York*)<br>Morteza Ashraphijuo, Columbia University (*New York, New York*)<br>Somayeh Sojoudi, New York University (*New York, New York*)<br>Ross Baldick, University of Texas-Austin (*Austin, Texas*)<br>**A Progressive Method for Electrical System Security Assessment within Large Areas**<br>Manuel Ruiz, Artelys (*Paris, France*)<br>Jean Maeght, RTE (*Versailles, France*)<br>Alexandre Marié, Artelys (*Paris, France*)<br>Othman Moumni Abdou, Artelys (*Paris, France*)<br>Patrick Panciatici, RTE (*Versailles, France*)<br>Arnaud Renaud, Artelys (*Paris, France*)<br>**Data-driven Optimization Approaches for Optimal Power Flow with Uncertain Reserves from Load Control**<br>Johanna Mathieu, University of Michigan (*Ann Arbor, Michigan*)<br>Siqian Shen, University of Michigan (*Ann Arbor, Michigan*)<br>Yiling Zhang, University of Michigan (*Ann Arbor, Michigan*)<br>Bowen Li, University of Michigan (*Ann Arbor, Michigan*)<br>**Marginal Loss Iteration Method for LMP Calculation**<br>Brent Eldridge, Federal Energy Regulatory Commission (*Washington, District of Columbia*)<br>Richard O'Neill, Federal Energy Regulatory Commission (*Washington, District of Columbia*)<br>Anya Castillo, Federal Energy Regulatory Commission (*Washington, District of Columbia*) |
| 10:30 AM | Break |

## Tuesday, June 23, 2015

10:45 AM Session T2-A (Meeting Room 3M-2)

**An Extended Hybrid Markovian and Interval Unit Commitment Considering Renewable Generation Uncertainties**

Peter Luh, University of Connecticut (*Storrs, Connecticut*)
Haipei Fan, University of Connecticut (*Storrs, Connecticut*)
Khosrow Moslehi, ABB Inc. (*Santa Clara, California*)
Xiaoming Feng, ABB Inc. (*Raleigh, North Carolina*)
Mikhail Bragin, University of Connecticut (*Storrs, Connecticut*)
Yaowen Yu, University of Connecticut (*Storrs, Connecticut*)
Chien-Ning Yu, ABB Inc. (*Santa Clara, California*)
Amir Mousavi, ABB Inc. (*Santa Clara, California*)

**Impact of ACOPF Constraints on Security-Constrained Unit Commitment**

Anya Castillo, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, New Mexico*)
Cesar Silva-Monroy, Sandia National Laboratories (*Albuquerque, New Mexico*)
Richard O'Neill, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
Carl Laird, Purdue University (*West Lafayette, Indiana*)

**An Exact Solution Method for Binary Equilibrium Problems with Comensation and the Power Market Uplift Problem**

Daniel Huppmann, Johns Hopkins University (*Washington, District of Columbia*)
Sauleh Siddiqui, Johns Hopkins University (*Baltimore, Maryland*)

Session T2-B (Meeting Room 3M-4)

**Modeling Flexible Primary Response in Security-Constrained Optimal Power Flow**

Daniel Kirschen, University of Washington (*Seattle, Washington*)
Yury Dvorkin, University of Washington (*Seattle, Washington*)
Pierre Henneaux, Tractebel Engineering (*Brussels, Belgium*)
Hrvoje Pandzic, University of Zagreb (*Zagreb,Croatia*)

**(Im)precision and Inaccuracy in Price and Load Forecasts: Resiliency Implications of Combining Forecast Data with Simulations of n-k Contingencies**

Jason Veneman, The MITRE Corporation (*McLean, Virginia*)
James Thompson, The MITRE Corporation (*McLean, Virginia*)
Brian Tivnan, The MITRE Corporation (*McLean, Virginia*)

**Parallel Solution of a Nonlinear Stochastic Programming Formulation for the N-1 Contingency Constrained ACOPF Problem**

Carl Laird, Purdue University (*West Lafayette, Indiana*)
Anya Castillo, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, New Mexico*)
Cesar Silva-Monroy, Sandia National Laboratories (*Albuquerque, New Mexico*)

Tuesday, June 23, 2015

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|---|---|
| 12:15 PM | Lunch |
| 1:30 PM | Session T3-A (Meeting Room 3M-2)<br>**Using High Performance Computing to Solve Unit Commitment Problem**<br>Feng Pan, Pacific Northwest National Laboratory (*Richland, Washington*)<br>Stephen Elbert, Pacific Northwest National Laboratory (*Richland, Washington*)<br>**A Distributed Approach to Large Scale Security Constrained Unit Commitment Problem**<br>Kaan Egilmez, Cambridge Energy Solutions (*Cambridge, Massachusetts*)<br>**Decentralized Robust Optimization Algorithms for Tie-Line Scheduling of Multi-Area Grid with Variable Wind Energy**<br>Bo Zeng, University of South Florida (*Tampa, Florida*)<br>Zhigang Li, Tsinghua University (*Beijing, China*)<br>Mohammad Shahidehpour, Illinois Institute of Technology (*Chicago, Illinois*)<br>Wenchuan Wu, Tsinghua University (*Beijing, China*)<br>Boming Zhang, Tsinghua University (*Beijing, China*) |
| | Session T3-B (Meeting Room 3M-4)<br>**A Corrective Approach to Security Constrained Unit Commitment and Dispatch**<br>Assef Zobian, Cambridge Energy Solutions (*Cambridge, Massachusetts*)<br>**Probabilistic Security-Constrained Unit Commitment with Generation and Transmission Contingencies**<br>Miguel Ortega-Vazquez, University of Washington (*Seattle, Washington*)<br>Yury Dvorkin, University of Washington (*Seattle, Washington*)<br>Ricardo Fernandez Blanco Carramolino, University of Washington (*Seattle, Washington*)<br>**Identifying and Controlling Risky Cascading Failures of Transmission Systems**<br>Daniel Bienstock, Columbia University (*New York, New York*) |
| 3:00 PM | Break |
| 3:15 PM | Session T4-A (Meeting Room 3M-2)<br>**SMART-Invest: A Stochastic, Dynamic Policy Model for Optimizing Investment in Wind, Solar and Storage**<br>Warren Powell, Princeton University (*Princeton, New Jersey*)<br>Javad Khazaei, Princeton University (*Princeton, New Jersey*)<br>**Large-Scale Stochastic Programming to Cooptimize Networks and Generation in the Face of Long-Run Uncertainties: What Lines Should We Build Now?**<br>Benjamin Hobbs, Johns Hopkins University (*Baltimore, Maryland*)<br>James McCalley, Iowa State University (*Ames, Iowa*)<br>Randell Johnson, Energy Exemplar (*Hartford, Connecticut*)<br>Jonathan Ho, Johns Hopkins University (*Baltimore, Maryland*)<br>Evangelia Spyrou, Johns Hopkins University (*Baltimore, Maryland*)<br>Pearl Donohoo, Johns Hopkins University (*Baltimore, Maryland*)<br>Qingyu Xu, Johns Hopkins University (*Baltimore, Maryland*)<br>Sang Woo Park, Johns Hopkins University (*Baltimore, Maryland*)<br>Jasmine Ouyang, Ethree (*San Francisco, California*)<br>**Electricity Market Solutions for Generator Revenue Sufficiency with Increased Variable Generation**<br>Todd Levin, Argonne National Laboratory (*Lemont, Illinois*)<br>Audun Botterud, Argonne National Laboratory (*Lemont, Illinois*)<br>**A Scalable Solution Framework for Stochastic Transmission and Generation Planning Problems**<br>Francisco Munoz, Sandia National Laboratories and Universidad Adolfo Ibañez (*Albuquerque, New Mexico*)<br>Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, New Mexico*) |

Tuesday, June 23, 2015

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| | Session T4-B (Meeting Room 3M-4)<br>**The Importance of Defining and Formulating Operating Reserve Requirements and Deployments**<br>Erik Ela, EPRI (*Palo Alto, California*)<br>Eamonn Lannoye, EPRI (*Palo Alto, California*)<br>Aidan Tuohy, EPRI (*Palo Alto, California*)<br>Bob Entriken, EPRI (*Palo Alto, California*)<br>Russ Philbrick, Polaris Systems Optimization (*Shoreline, Washington*)<br>**Ramping Effect on Forecast Use: Integrated Ramping as a Mitigation Strategy**<br>Clayton Barrows, National Renewable Energy Laboratory (*Golden, Colorado*)<br>Victor Diakov, National Renewable Energy Laboratory (*Golden, Colorado*)<br>Greg Brinkman, National Renewable Energy Laboratory (*Golden, Colorado*)<br>Aaron Bloom, National Renewable Energy Laboratory (*Golden, Colorado*)<br>Paul Denholm, National Renewable Energy Laboratory (*Golden, Colorado*)<br>**A Study on Wind Dispatchability**<br>Feng Qiu, Argonne National Laboratory (*Lemont, Illinois*)<br>Jianhui Wang, Argonne National Laboratory (*Lemont, Illinois*)<br>**Look-ahead Scheduling of Energy, Reserves and Ramping Under Uncertainty in a Two-Settlement Framework**<br>Ray Zimmerman, Cornell University (*Ithaca, New York*)<br>Alberto Lamadrid, Lehigh University (*Bethlehem, Pennsylvania*)<br>Daniel Muñoz-Alvarez, Cornell University (*Ithaca, New York*)<br>Carlos Murillo-Sánchez, Universidad Nacional de Colombia (*Manizales, Colombia*)<br>Robert Thomas, Cornell University (*Ithaca, New York*) |
| 5:15 PM | Adjourn |

Wednesday, June 24, 2015

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|---|---|
| 8:15 AM | Arrive and welcome (Meeting Room 3M-2) |
| 8:30 AM | Session W1-A (Meeting Room 3M-2)<br>**A Stochastic Dispatchable Pricing Scheme for Electric Energy Day-Ahead Markets**<br>John Birge, University of Chicago (*Chicago, Illinois*)<br>Audun Botterud, Argonne National Laboratory (*Argonne, Illinois*)<br>Chao Li, Arizona State University (*Tempe, Arizona*)<br>**A New Dual Decomposition Method and Parallel Software Implementation for Large-Scale Stochastic Mixed-Integer Programs**<br>Kibaek Kim, Argonne National Laboratory (*Lemont, Illinois*)<br>Victor M. Zavala, Argonne National Laboratory (*Lemont, Illinois*)<br>**Preserving Revenue Adequacy in FTR Markets with Changing Topology**<br>Aleksandr Rudkevich, Newton Energy Group LLC (*Boston, Massachusetts*)<br>Evgeniy Goldis, Boston University (*Boston, Massachusetts*)<br>Michael Caramanis, Boston University (*Boston, Massachusetts*)<br>Pablo Ruiz, Boston University (*Boston, Massachusetts*)<br>Xiaoguang Li, Boston University (*Boston, Massachusetts*)<br>Richard Tabors, Tabors Caramanis Rudkevich (*Boston, Massachusetts*) |
| | Session W1-B (Meeting Room 3M-4)<br>**Ensuring the Operational Security of Power Grids Using the On-Line Dynamic Security Assessment Technology**<br>Lei Wang, Powertech Labs Inc. (*Surrey, British Columbia*)<br>**Grid Architecture as a Means to Understand the Interactions of Power Systems, Markets, and Grid Control Systems**<br>Jeffrey Taft, Pacific Northwest National Laboratory (*Richland, Washington*)<br>**Predicting Predictions: The Use of Bayesian Model Averaging To Select Models**<br>Colin Gounden, Via Science (*Cambridge, Massachusetts*)<br>Jeremy Taylor, Via Science (*Montréal, Quebec*) |
| 10:00 AM | Break |
| 10:15 AM | Session W2-A (Meeting Room 3M-2)<br>**Topology Control Algorithms Impacts in Day-Ahead Markets - Simulations in PJM**<br>Pablo Ruiz, The Brattle Group (*Cambridge, Massachusetts*)<br>Michael C. Caramanis, Boston University (*Boston, Massachusetts*)<br>Evgeniy Goldis, Newton Energy Group (*Boston, Massachusetts*)<br>Bhavana Keshavamurthy, PJM Interconnection (*Valley Forge, Pennsylvania*)<br>Xiao Li, Boston University (*Boston, Massachusetts*)<br>C. Russ Philbrick, Polaris Systems Optimization (*Shoreline, Washington*)<br>Aleksandr Rudkevich, Newton Energy Group (*Boston, Massachusetts*)<br>Richard Tabors, Tabors Caramanis Rudkevich (*Boston, Massachusetts*)<br>**Flexible Transmission Decision Support Systems**<br>Kory Hedman, Arizona State University (*Tempe, Arizona*)<br>Mostafa Sahraei-Ardakani, Arizona State University (*Tempe, Arizona*)<br>Mojdeh Abdi-Khorsand, Arizona State University (*Tempe, Arizona*)<br>Xingpeng Li, Arizona State University (*Tempe, Arizona*)<br>Pranavamoorthy Balasubramanian, Arizona State University (*Tempe, Arizona*)<br>Akshay Korad, Arizona State University (*Tempe, Arizona*)<br>**Co-Optimization of Battery Storage Over Multiple Revenue Streams and Time Scales**<br>Warren Powell, Princeton University (*Princeton, New Jersey*)<br>Harvey Cheng, Princeton University (*Princeton, New Jersey*)<br>**Energy Storage: A Study Identifying Business Cases for France by 2030**<br>Guillaume Tarel, Artelys (*Montréal, Canada*) |

Wednesday, June 24, 2015

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|---|---|
| | Session W2-B (Meeting Room 3M-4)<br>**A Toolbox for Exploring AC OPF Formulations, Datasets and Solution Methods**<br>Lisa Tang, University of Wisconsin – Madison (*Madison, Wisconsin*)<br>Christopher DeMarco, University of Wisconsin – Madison (*Madison, Wisconsin*)<br>Michael Ferris, University of Wisconsin – Madison (*Madison, Wisconsin*)<br>Bernard Lesieutre, University of Wisconsin – Madison (*Madison, Wisconsin*)<br>Byungkwon Park, University of Wisconsin – Madison (*Madison, Wisconsin*)<br>**The FLEX DA/RT Co-optimization Model Method - A Better Unit Commitment for an Uncertain Grid**<br>Charles Noble, ACES (*Carmel, Indiana*)<br>**Strong SOCP Relaxations for Optimal Power Flow Problems**<br>Andy Sun, Georgia Institute of Technology (*Atlanta, Georgia*)<br>**Addressing Uncertainty How to Model and Solve Energy Optimization Problems**<br>Alkis Vazacopoulos, Optimization Direct, Inc. (*Harrington Park, New Jersey*) |
| 12:15 PM | Adjourn |

**Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software**

**Abstracts**

Monday, June 22

Session M1 (Monday, June 22, 8:30 AM, Meeting Room 3M-2)

### INTRODUCTION

**Dr. Richard O'Neill**, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, District of Columbia*)

### COMPUTATIONAL AND DESIGN NEEDS IN RTO MARKETS: A PJM PERSPECTIVE

**Dr. Paul Sotkiewicz**, Chief Economist, PJM Interconnection, LLC (*Audubon, Pennsylvania*)

RTO markets are facing new challenges going forward from gas/electric coordination to increasingly stringent environmental compliance to changing patterns of energy demand. Gas/electric coordination requires better computational algorithms to speed up solution times. Potential options for state plans under the Clean Power Plan may require new ways to model hundreds or thousands of units with run time restrictions to preserve reliability in operations and efficiently allocate limited run hours over a single year or many years. Finally, since the start of the recession in 2007, patterns of energy demand and peak load have changed dramatically and requires a different look at load forecasting models both in the shirt term and long term and thinking outside the box in terms of possible demand drivers. Improvements in all these areas will help in price formation in the energy and capacity markets and help potentially further reduce uplift while enhancing reliability.

### DAY-AHEAD MARKET CLEARING SOFTWARE PERFORMANCE IMPROVEMENT

**Dr. Yonghong Chen**, Principal Advisor, MISO (*Carmel, Indiana*)
**Mr. Aaron Casto**, Senior Manager, Day-ahead Market Administration, MISO (*Carmel, Indiana*)
**Dr. Xing Wang**, R&D Director, Alstom (*Redmond, Washington*)
**Dr. Jie Wan**, Lead, Optimization Applications, Alstom (*Redmond, Washington*)
**Dr. Fengyu Wang**, Market Development Analyst, MISO (*Carmel, Indiana*)

This presentation introduces recent work from MISO and Alstom Grid to improve the day-ahead market clearing software performance. It starts with an assessment of current day-ahead market clearing process and identifies bottleneck areas under exiting market clearing software. It then introduces the R&D collaboration to improve the efficiency of the process, including improving security constrained unit commitment incremental solving capability, alternative SCUC heuristic approaches, commitment reason identification and post commitment analysis, as well as introducing binary constraints to incorporate voltage and local reliability commitment requirement.

**SPP SECURITY CONSTRAINED UNIT COMMITMENT ENHANCEMENT AND PERFORMANCE IMPROVEMENT**

**Dr. Jie Wan**, Lead, Market Applications, Alstom Grid (*Redmond, Washington*)
**Mr. Gary Cate**, Supervisor, Market Forensics and Analysis, SPP (*Little Rock, Arkansas*)
**Mr. David Gary**, Senior Power System Engineer, Alstom Grid (*Redmond, Washington*)
**Dr. Xing Wang**, R&D Director, Alstom Grid (*Redmond, Washington*)

In its first year, the SPP Integrated Marketplace generated an estimated $301 million in net savings to SPP's region with the combination of its market and BA function. The extensive inclusion of SCUC in the overall market clearing process is key to the market efficiency. The co-optimization of energy, regulation-up, regulation-down,spinning reserve and supplemental reserve also helps to improve the overall solution. SCUC is included in multiple different studies such as DBDA-RUC, DAM, DA-RUC, ID-RUC and PA-RUC. Extensive scarcity and emergency steps, as well as a full mitigation process, are automatically triggered in the SCUC algorithm. Due to this, SPP requires a fast and efficient SCUC algorithm for their complicated, large scale model. A multiple-step SCUC algorithm is implemented to improve the solution quality and MIP solution performance. This also provides the flexibility to adapt to the different phases of SCUC study.

<u>Session M2 (Monday, June 22, 10:45 AM, Meeting Room 3M-2)</u>

**CONVEX HULL PRICING: RIGOROUS ANALYSIS AND IMPLEMENTATION CHALLENGES**

**Dr. Dane Schiro**, Analyst, ISO New England (*Holyoke, Massachusetts*)
**Dr. Tongxin Zheng**, Technical Manager, ISO New England (*Holyoke, Massachusetts*)
**Dr. Feng Zhao**, Lead Analyst, ISO New England (*Holyoke, Massachusetts*)
**Dr. Eugene Litvinov**, Chief Technologist, ISO New England (*Holyoke, Massachusetts*)

Convex Hull Pricing is commonly cited as a desirable pricing scheme because of its "uplift minimization" property. Unfortunately, this and other aspects of Convex Hull Pricing are easily misunderstood or not completely appreciated. This talk will summarize the most important properties of the pricing method and will analyze a variety of practical considerations. Several of the interesting properties will be illustrated through simple examples, and open questions will be introduced to spur additional research.

**PRICE ENHANCEMENTS FOR REAL-TIME AND DAY-AHEAD MARKETS**

**Dr. Congcong Wang**, Market Design Engineer, MISO (*Carmel, Indiana*)
**Dr. Juan Li**, Principle Market Engineer, MISO (*Carmel, Indiana*)
**Dr. Dhiman Chatterjee**, Senior Manager, Market Design, MISO (*Carmel, Indiana*)
**Mr. Robert Merring**, Manager, Market Engineering, MISO (*Carmel, Indiana*)

This presentation highlights MISO's recent price formation efforts to provide efficient market prices that are truly reflective of marginal system cost under all conditions. It starts with an examination of the current price deficiencies and identifies opportunities of price enhancements. It then presents MISO's market design developments to advance price efficiency and reduce uplift payments, including Pricing under Emergency Conditions to appropriately price the emergency energy and demand response resources and Extended Locational Marginal Prices (ELMP) to more accurately reflect the cost of fast-start resources to meet demands. The presentation finishes with a review of ELMP production results based on the available data since the effective date of 3/1/2015. The analysis includes MISO's recent ELMP design improvements based on recommendations from its IMM during MISO ELMP parallel operation.

**APPROACHES TO REDUCE ENERGY UPLIFT AND PJM EXPERIENCES**

**Dr. Ying Xiao**, Senior Principal Power Systems Engineer, Alstom Grid (*Redmond*, *Washington*)
**Dr. Paul Sotkiewicz**, Chief Economist, PJM Interconnection (*Valley Forge*, *Pennsylvania*)
**Mr. F. Stuart Bresler, III,** Vice President - Market Operations, PJM Interconnection (*Valley Forge, Pennsylvania*)

Uplift payments are introduced to ensure resources do not operate at a loss when following Regional Transmission Organizations (RTO)/Independent System Operators (ISO) dispatch instructions. For any energy markets when the market clearing price (MCP) cannot fully compensate offers of dispatched resources, uplift payments have to incur. There can be various causes of uplift. One major reason is, inflexible resources, such as combustion turbines (CTs), operating at economic minimum. They may be needed by RTOs for reactive control, black start, congestion alleviation or needed for only part of the day, but, due to a long minimum runtime, it is kept on even when operation is uneconomic for the resource. These resources are not naturally able to set the MCP, therefore must be compensated through uplift.

In early 2014, PJM and ALSTOM Grid launched a project to reduce uplift payment in both PJM Day-Ahead (DA) market and Real-Time (RT) Markets. The technical software has been operating in the PJM production environment since the end of 2014.

This presentation focuses on the approaches of reducing uplift in the PJM DA and RT business processes and PJM experiences. The approaches are based on the idea of binding transmission constraints or PJM manually created interface constraints to make sure the MCPs can cover dispatched resource offer prices. With the uplift reduction method being implemented in the market clearing mechanism, PJM has seen much less compensation out of market.

Session M3 (Monday, June 22, 1:30 PM, Meeting Room 3M-2)

**NYISO RETROSPECTIVE MARKET SIMULATION TOOLKIT**

**Mr. Charles Alonge**, Senior Software Developer, NYISO (*Rensselaer, New York*)
**Mr. Tate Hoag**, Performance Analysis Engineer, NYISO (*Rensselaer, New York*)
**Mr. Jiaxiao Hu**, Senior Software Developer, NYISO (*Rensselaer, New York*)
**Mr. Bruce Budris**, Performance Analysis Engineer, NYISO (*Rensselaer, New York*)
**Dr. Muhammad Marwali**, Manager, Technology Development, NYISO (*Rensselaer, New York*)

Under the auspices of the Standard Market Design 2.0 project (SMD2), NYISO made significant changes to its Business Management System (BMS) to further optimize energy, operating reserves, and regulation in both the day-ahead and real-time energy market activities. NYISO's real-time market includes both a 15-minute real-time commitment system (RTC) and a 5-minute real-time dispatch system (RTD). RTC optimizes/commits the start of gas turbines and handles the economic scheduling of external transactions while RTD uses the commitment information from RTC and further analyzes the upcoming energy needs and moves resources efficiently to satisfy those needs.

During the development of the BMS system under SMD2 a need was identified to store market input and output conditions so multiple different market parameters and inputs could be tested retrospectively for study and audit purposes. The market input and output conditions along with configuration information formed the basis of a market "save case". NYISO's day-ahead and real-time market passes have been designed to capture a save case after each market interval and pass is executed. For the past two years, NYISO, with the help of FERC funding, has been improving upon the save case features of our BMS to enhance the market rerun and analysis processes. An overview of NYISO rerun software, tools, and applications will be presented along with some preliminary results from recent market re-run studies.

**MISO EXPERIENCES WITH CONGESTION MANAGEMENT ENHANCEMENT**

**Dr. Li Zhang**, Manager, Market Analysis, MISO (*Carmel, Indiana*)
**Mr. Kevin SHerd**, Director, Forward Operation Planning, MISO (*Carmel, Indiana*)
**Ms. Shu Xu**, Senior Engineer, Market Analysis, MISO (*Carmel, Indiana*)
**Mr. Robert Merring**, Manager, Market Engineering, MISO (*Carmel, Indiana*)
**Dr. Chuck Hansen**, Senior Engineer, MISO (*Carmel, Indiana*)

To improve congestion management, MISO recently implemented two enhancements to its markets: Transmission Constraint Demand Curves (TCDCs) and the elimination of transmission constraint deadbands. This report presents the background and operational experience MISO has gained from the enhancements.

Transmission constraint deadbands were set by MISO operators to reduce the limit after a constraint initially bound. The purpose was to limit the frequency with which constraints bind and then immediately unbind. It was found, however, that the deadbands actually caused more congestion and price spikes, and also under-utilized the transmission system. After analysis and trials, the transmission deadbands were removed in October 2013.

MISO also implemented TCDCs to better manage congestion in the day-ahead and real-time markets. MISO initially used Constraint Relaxation to manage violated constraints, but this produced inefficiently low shadow prices that distorted associated LMPs. MISO originally developed a flat single-value Marginal Value Limit (MVL), but this contributed to real-time price volatility and underfunding of the Real-Time Excessive Congestion Fund. MISO developed a transmission voltage level based MVL grouping, and also improved the MVL approach by adding a second, lower MVL value for exceedances between 100 and 102% of the binding limit.

**A MARGINAL EQUIVALENT ALGORITHM AND ITS APPLICATION IN COORDINATED MULTI-AREA DISPATCH PROBLEM**

**Dr. Feng Zhao**, Lead Analyst/Engineer, ISO New England (*Holyoke, Massachusetts*)
**Dr. Eugene Litvinov**, Chief Technologist, ISO New England (*Holyoke, Massachusetts*)

A large power system is often composed of several interconnected control areas, each operated by a System Operator (SO). To achieve the economic efficiency of the system, the SOs need to coordinate their dispatch problems in real-time operations. Different coordination methods have been proposed in the past. We introduce a novel "marginal equivalent" decomposition algorithm that partitions a linear programming problem into subproblems and coordinates their solutions by exchanging the information of free variables and binding constraints. Convergence of the algorithm is proven. The method is applied to coordinating the dispatch problems of multiple areas. Numerical testing results demonstrate the fast convergence of the method and a moderate amount of information exchange between areas.

Session M4 (Monday, June 22, 3:15 PM, Meeting Room 3M-2)

**DAY-AHEAD WINDOW OPTIMIZATION**

**Mr. Muhammad Marwali**, Manager of Technology Development, NYISO (*Rensselaer, New York*)
**Mr. Fred Adadjo**, Planning Engineer, NYISO (*Rensselaer, New York*)

Natural gas has become the fuel of choice for electric generation, and while currently, almost half of the total installed capacity in the ISO/RTO regions comes from natural-gas fired generation, that number is expected to increase in many regions over the next several years. The gas and electric markets have different operating days and different scheduling times. The gas day runs from 10 AM to 10 AM (ET), while the electric day in New York runs from 12 AM to 12 AM. This mismatch requires generators to nominate gas to cover one gas day, but two electric days. Schedules for the second electric day are not yet known when generators nominate gas.

In this presentation, we assess the impact of changing the electric day to match the gas day, i.e., the impact of a "common energy day" between the gas and electric sectors, as part of the overall frame of improving gas and electric coordination.

Various electric day start times were analyzed, corresponding to the current gas day start time, as well as different gas day start times. Significant analysis was conducted looking at factors such as production cost differences, unit commitment changes, and transaction changes. Overall, there appear to be production cost savings associated with some of the proposed electric day times. However, given the unit commitment changes, potential transaction changes, and limitations to the analysis as conducted, only a 4 AM or earlier start to the electric day improves product production costs.

### CONSIDER NATURAL GAS PIPELINE CONSTRAINTS IN ELECTRICITY MARKET OPERATIONS

**Dr. Xing Wang**, Director, Software Engineering, Alstom Grid (*Redmond, Washington*)
**Dr. Tongxin Zheng**, Manager, ISO-NE (*Holyoke, Massachusetts*)

With the significant increase of Shale Gas production in the U.S. and the recent EPA's Clean Power Plan, it can be expected that the percentage of natural gas in the fuel mix of power generation will continue to to grow in a faster path. In fact, regions such as ISO-NE already has about 50% of its generation capacity from natural gas fired generators. Experiences of ISO-NE and PJM from the past several cold winters have demonstrated strong needs to improve the coordination between gas and electric system/market operations. FERC has been driving the coordination activities for enhanced reliability and efficiency.

This presentation will first review the challenges that ISO-NE and other RTOs are facing in terms of risks of insufficient and uncertain natural gas supply under extreme weather conditions. A simplified pipeline model and its mapping to electric power system is created for modeling gas constraints in electricity market operations, such as Day-ahead reliability unit commitment. A hybrid model is proposed to combine market offer based unit commitment and dispatch with physical fuel model and pipeline topology model, in order to expand SCUC and SCED to cover gas pipeline contingencies and constraints.

<u>Session M5 (Monday, June 22, 4:30 PM, Meeting Room 3M-2)</u>

### TACKLE LOAD AND INTERCHANGE UNCERTAINTIES: PJM'S EXPERIENCES

**Dr. Hong Chen**, Senior Consultant, PJM (*Audubon, Pennsylvania*)

Handling uncertainties has always been part of the system operation to mitigate operation risks. Besides load uncertainty and growing uncertainty brought by renewable resources, interchange uncertainty is becoming one of the primary uncertainty factors faced by system operators today. Uncertainties directly impact market efficiency, and remain to be a challenge for years. This presentation will review the PJM's experiences on tracking the uncertainties, quantifying the impact, as well as improving the processes to manage the uncertainties.

**VOLTAGE STABILITY ASSESSMENT IMPLEMENTATION IN NYISO: TOWARD A BETTER UTILIZATION OF THE TRANSMISSION GRID**

**Mr. De Tran**, Supervisor, Power Systems Application Engineering, NYISO (*Rensselaer, New York*)

**Mr. Vladimir Brandwajn**, Group Senior Principal Consultant, ABB Inc. (*Santa Clara, California*)

Higher energy market efficiency can be achieved through better utilization of the transmission grid. This presentation reports on the progress by NYISO in developing an advanced on-line Voltage Stability Assessment (VSA) application that is intended to enable the NYISO to efficiently utilize its transmission capacity to improve the market efficiency while maintaining system reliability. The on-line Voltage Stability Assessment is based on a continuation of power load flow technique, which runs periodically based on the static State Estimator solution, to determine the voltage stability margin of a power transfer through a given interface in real time. The objective of the development of the application was to replace the offline calculated incremental margins, which are being used by the Market Management System (MMS), with the real-time VSA calculated margins. The replacement of the offline with the real-time calculated margins, which are based on the current network topology, would allow the Real Time Commitment (RTC) and Real Time Dispatch (RTD) applications to perform their commitment and dispatch functions more accurately and efficiently. The VSA function is integrated into the Energy Management System (EMS) and is currently being tested and validated by the NYISO.

Tuesday, June 23

Session T1-A (Tuesday, June 23, 8:30 AM, Meeting Room 3M-2)

**STOCHASTIC OPTIMIZATION FOR UNIT COMMITMENT AND ELECTRICITY MARKET OPERATION: A REVIEW**

**Dr. Zhi Zhou**, Computational Engineer, Argonne National Laboratory (*Lemont, Illinois*)
**Dr. Audun Botterud**, Energy System Engineer, Argonne National Laboratory (*Lemont, Illinois*)

To better account for the uncertainty in current power systems with increasing levels of renewable energy, unit commitment (UC) formulations based on stochastic optimization have received substantial interest in the research community in recent years. In this talk, we present a comprehensive review of the application of stochastic programming to the UC problem and associated electricity market operations. The review discusses different characteristics of stochastic UC formulations, including objective functions, risk preferences, uncertainty representation, reserve deployment strategies, solution algorithms, and test systems. Moreover, we compare the performance of stochastic and deterministic UC models reported in the literature, in terms of cost reduction, reliability improvement, and other metrics. Finally, the review summarizes the current status and prospects for industrial adaptation of stochastic methods in electricity market operations, focusing on selected markets/regions in the United States and Europe.

**TWO-STAGE STOCHASTIC UNIT COMMITMENT MODELS WITH EXPLICIT RELIABILITY REQUIREMENTS THROUGH CONDITIONAL VALUE-AT-RISK**

**Dr. Andrew Liu**, Assistant Professor, Purdue University (*West Lafayette, Indiana*)
**Dr. Qipeng Zheng**, Assistant Professor, University of Central Florida (*Orlando, Florida*)
**Yuping Huang**, PhD Student, University of Central Florida (*Orlando, Florida*)

The bulk electricity grid is such a delicate system that supply and demand of electricity must be balanced at all time to maintain system reliability.

Increasing penetration of variable energy resources (VERs), especially wind and solar energy, has added great stress to keep such a balance.

Traditionally variations of a power system are controlled through the operating reserves. While a natural idea to accommodate higher penetration VERs and to maintain system reliability is to require a higher operating reserve level, such a requirement will also incur hefty costs that eventually have to be shouldered by consumers. In our view, the tension between economics and reliability of power grids operation resembles the classic trade-off between expected investment returns and risks in the financial sector. Borrowing the concept from the modern portfolio theory, we propose to use the risk measure, Conditional Value-at-Risk (CVaR), to explicitly account for both the system-level risks, and each power plants contribution to the reliability of the system. Such a risk measure can be included as a constraint in a two-stage stochastic unit commitment (SUC) model to replace the fixed operating reserve requirement. With the scenario-coupling CVaR constraints, the resulting two-stage model cannot be directly solved by the classic Benders decomposition. We propose a modified Benders in this work, and the initial numerical results based on a 7-bus test system show that the CVaR-based.

### A CHANCE-CONSTRAINED UNIT COMMITMENT MODEL FOR POWER SYSTEMS WITH HIGH PENETRATION OF RENEWABLE ENERGY

**Dr. Gabriela Martinez**, Postdoctoral Associate, Cornell University (*Ithaca, New York*)
**Dr. Lindsay Anderson**, Assistant Professor, Cornell University (*Ithaca, New York*)

We consider a risk-averse optimization model for the security constrained unit commitment problem. The optimal day-ahead scheduling of the system is formulated as a chance-constrained optimization model in which the load balance of the system is satisfied with a user-defined probability level. The assumption of a specific underlying probability distribution is avoided and a flexible data-driven uncertainty set is used to obtain a feasible risk-averse scheduling of the system. The method is flexible in allowing a range of risk into the problem from higher-risk to robust solutions. Numerical results show that our approach provides significant scalability for the stochastic problem, allowing the use of very large sample sets to represent uncertainty in a comprehensive way. This provides significant promise for scaling to larger networks because the approach decomposes the stochastic and the mixed-integer problem which avoids multiplicative scaling of the dimension that is prevalent in two-stage stochastic programming methods.

### STOCHASTIC UNIT COMMITMENT AT SCALE: COST SAVINGS ANALYSIS FOR ISO-NE

**Dr. Jean-Paul Watson**, Distinguished Member of Technical Staff, Sandia National Laboratories (*Albuquerque, New Mexico*)
**Dr. David Woodruff**, Professor, University of California Davis (*Davis, California*)

Studies of the cost savings potential for stochastic unit commitment relative to existing deterministic methods are limited, and it is unclear to what degree results from specific geographic regions (e.g., Ireland and the UK) generalize. Further, the details of production cost simulations are critical in the quantification of cost savings, as many existing simulators are partially prescient, fail to simulate out-of-sample, or both. Building on a DOE ARPA-e funded effort, we have recently developed scalable solution technology for stochastic unit commitment, coupled with accurate scenario generation methods and production cost simulators. In this talk, we apply our technologies to a study of ISO-NE with EWITS wind penetration levels and higher. We analyze the cost savings results for various levels of wind penetration, and find that reliability impacts are more significant than costs - particularly at high penetration levels. Similarly, we show that standard methods of quantifying the value of a stochastic unit commitment solution are not always indicative of simulated, out-of-sample cost savings. Insights into limitations of deterministic reserve carrying rules in the face of high wind penetration levels will also be discussed.

Session T1-B (Tuesday, June 23, 8:30 AM, Meeting Room 3M-4)

### NEAR-GLOBAL SOLUTIONS OF NONLINEAR POWER OPTIMIZATION PROBLEMS: THEORY, NUMERICAL ALGORITHM, AND CASE STUDIES

**Dr. Javad Lavaei**, Assistant Professor, Columbia University (*New York, New York*)
**Mr. Ramtin Madani**, PhD Student, Columbia University (*New York, New York*)
**Mr. Abdulrahman Kalbat**, PhD Student, Columbia University (*New York, New York*)
**Mr. Morteza Ashraphijuo**, PhD Student, Columbia University (*New York, New York*)
**Dr. Somayeh Sojoudi**, Research Scientist, New York University (*New York, New York*)
**Dr. Ross Baldick**, Professor, University of Texas-Austin (*Austin, Texas*)

In this talk, we study the potentials of semidefinite programming (SDP) relaxations for nonlinear power optimization problems such as the power flow problem, security-constrained optimal power flow, and state estimation. The existence of a rank-1 matrix solution to the SDP relaxation enables the recovery of a global solution of the original problem. We show that real-world power networks have low treewidth, and as a result the SDP relaxation always has a low-rank solution. For example, the SDP relaxation of a power optimization solved over the NY Grid would have rank at most 40. By leveraging this fact, we design a penalized SDP relaxation to reduce the rank to 1, leading to a near-global solution. As a case study, we demonstrate that the proposed relaxation is able to find feasible solutions for the optimal power flow problem for Polish test systems with a global optimality guarantee of at least 99%. We develop a methodology to systematically design the penalty term, as a proxy for the rank constraint, in the penalized SDP problem.

In the context of the power flow problem, we prove that the proposed technique always finds a feasible solution for arbitrary networks as long as the voltage angles are not too large. Finally, we propose a low computation, distributed algorithm to solve the penalized SDP relaxation. Unlike the existing second-order methods that cannot handle large SDP problems, our approach leverages the low treewidth of power grids and is very efficient.

### A PROGRESSIVE METHOD FOR ELECTRICAL SYSTEM SECURITY ASSESSMENT WITHIN LARGE AREAS

**Mr. Manuel Ruiz**, Optimization Consultant, Artelys (*Paris, France*)
**Mr. Jean Maeght**, RTE (*Versailles, France*)
**Mr. Alexandre Marié**, Artelys (*Paris, France*)
**Mr. Othman Moumni Abdou**, Artelys (*Paris, France*)
**Mr. Patrick Panciatici**, RTE (*Versailles, France*)
**Mr. Arnaud Renaud**, Artelys (*Paris, France*)

Transmission System Operators (TSOs) in Europe are facing system security issues that will become more and more challenging considering the growth of intermittent power generation (renewable sources) and the ambition to create a single European electricity market.

Theses system security rules, such as voltage limits for each substation and current intensity bounds on each line, have to be satisfied while cutting down active power losses on lines by optimizing the commitment of production units and the configuration of special devices set up on the lines, such as tap-changer or phase-shifter, given loads, fatal productions and injections (Optimal Power Flow- OPF).

A progressive method based on an OPF model with Alternative Current formulation is introduced to determine whether an electrical network is in a secure state or not. A progressive filtering approach is used to detect the reasons why a network states is unfeasible and gives curatives actions to keep the system in a secure state.

Preliminary results on the French and European power systems network demonstrate the interest of this approach on real-life cases. These cases were solved in few minutes (over 1000 generators, 3500 loads, 4000 substations, 9000 branches and up to 75 Phase-Shifting transformer configurations).

This work have been done within the ITesla research project (Innovative Tools for Electrical Security within Large Areas) that aims at improving network operations with a new security assessment tool.

**DATA-DRIVEN OPTIMIZATION APPROACHES FOR OPTIMAL POWER FLOW WITH UNCERTAIN RESERVES FROM LOAD CONTROL**

**Dr. Johanna Mathieu**, Assistant Professor, University of Michigan (*Ann Arbor, Michigan*)
**Dr. Siqian Shen**, Assistant Professor, University of Michigan (*Ann Arbor, Michigan*)
**Yiling Zhang**, PhD Student, University of Michigan (*Ann Arbor, Michigan*)
**Bowen Li**, PhD Student, University of Michigan (*Ann Arbor, Michigan*)

We investigate data-driven optimization methods that are suited to dispatching power systems with uncertain balancing reserves provided by load control. Specifically, we formulate a chance-constrained optimal power flow (OPF) problem in which we aim to satisfy constraints that include stochastic variables jointly with a specified probability or individually with different probability guarantees. We focus on the realistic case where we do not have full knowledge of uncertainty distributions and compare the performance of distribution-free approaches with other stochastic optimization methods. We run experimental studies on the IEEE 9-bus and 39-bus test systems assuming uncertainty in load, load control reserve capacities, and renewable energy generation. The results show the computational efficacy of the distributionally robust approach and its flexibility in trading off between cost and robustness of OPF solutions driven by the amount of data describing the uncertainty.

**NEW MARGINAL LOSS CALCULATION FOR LMPS**

**Mr. Brent Eldridge**, Operations Research Analyst, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
**Ms. Anya Castillo**, Operations Research Analyst, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
**Dr. Richard O'Neill**, Cheif Economic Advisor, Federal Energy Regulatory Commission (*Washington, District of Columbia*)

The paper presents a new method for estimating line losses when solving a DC optimal power flow (DCOPF) with endogenous line loss estimation. We present a DCOPF model and propose a method, First Order Improvement of Losses, which uses only linear constraints and does not require additional solutions to AC power flow equations. We compare FOIL to the initial solution and to results using successive linearization.

Session T2-A (Tuesday, June 23, 10:45 AM, Meeting Room 3M-2)

**AN EXTENDED HYBRID MARKOVIAN AND INTERVAL UNIT COMMITMENT CONSIDERING RENEWABLE GENERATION UNCERTAINTIES**

**Dr. Peter Luh**, Professor, University of Connecticut (*Storrs, Connecticut*)
**Ms. Haipei Fan**, Graduate Student, University of Connecticut (*Storrs, Connecticut*)
**Dr. Khosrow Moslehi**, ABB, Inc. (*Santa Clara, California*)
**Dr. Xiaoming Feng**, Research Fellow, ABB Inc. (*Raleigh, North Carolina*)
**Mr. Mikhail Bragin**, Graduate Student, University of Connecticut (*Storrs, Connecticut*)
**Mr. Yaowen Yu**, Graduate Student, University of Connecticut (*Storrs, Connecticut*)
**Dr. Chien-Ning Yu**, ABB, Inc. (*Santa Clara, California*)
**Dr. Amir Mousavi**, ABB, Inc. (*Santa Clara, California*)

Grid integration of intermittent renewables is important to reduce the dependence on fossil fuels and to cut greenhouse gas emissions. The problem is challenging in view of the huge amount of uncertainties and potential transmission congestions. Recently, we developed a hybrid Markovian and interval approach. The idea is to divide the generation of a conventional unit into a Markovian component that depends on the local state, and an interval component that covers extreme non-local states. The problem was solved by using branch-and-cut. Results are good, but could be conservative for certain system configurations, e.g., when wind farms are located at remote sites without accompanying conventional units. In this presentation, an extended approach is established to reduce the conservativeness while improving computational efficiency. This is done by allowing the generation of a conventional unit to depend on the states of non-local renewable generations. The problem is solved by using a synergistic combination of our recent Surrogate Lagrangian Relaxation (SLR) and branch-and-cut. SLR overcomes major difficulties of traditional LR, and is used to decompose the problem into individual node subproblems which are solved by using branch-and-cut with much reduced complexity. Numerical results demonstrate that the over-conservativeness of the original approach is much alleviated, and the new method is effective in terms of solution quality and computational efficiency.

### IMPACT OF ACOPF CONSTRAINTS ON SECURITY-CONSTRAINED UNIT COMMITMENT

**Ms. Anya Castillo**, Operations Research Analyst, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
**Dr. Jean-Paul Watson**, Scientist, Sandia National Laboratories (*Albuquerque, New Mexico*)
**Dr. Cesar Silva-Monroy**, Scientist, Sandia National Laboratories (*Albuquerque, New Mexico*)
**Dr. Richard O'Neill**, Cheif Economic Advisor, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
**Dr. Carl Laird**, Associate Professor, Purdue University (*West Lafayette, Indiana*)

Because operational constraints on thermal units require these resources to be committed in advance of when they are needed, system operators solve a unit commitment optimization problem in the day-ahead. At times, certain out-of-merit units need to be committed for reliability reasons. Typically such units are committed in a reliability run and subsequently would receive make-whole payments so that market participants are not forced to operate at a loss. Ideally the more operational constraints and physical limitations (which would affect real-time dispatch) included in the day-ahead unit commitment optimization problem, the better convergence between day-ahead and real-time pricing. We propose a SCUC+ACOPF approach in this work.

### AN EXACT SOLUTION METHOD FOR BINARY EQUILIBRIUM PROBLEMS WITH COMPENSATION AND THE POWER MARKET UPLIFT PROBLEM

**Dr. Daniel Huppmann**, Postdoctorate Fellow, Johns Hopkins University (*Baltimore, Maryland*)
**Dr. Sauleh Siddiqui**, Assistant Professor, Johns Hopkins University (*Baltimore, Maryland*)

We propose a novel way to solve for Nash equilibria in games with binary decision variables. We include the incentive compatibility constraints derived from non-cooperative game theory directly into an optimization framework rather than using first-order conditions of a linearization, or relaxation of integrality conditions. The reformulation offers a new approach to obtain and interpret dual variables in integer games using the benefit or loss from deviation rather than marginal relaxations. Furthermore, the method endogenizes the trade-off between overall market efficiency and the budget for compensation payments necessary to align incentives of players.

The reformulation approach is used on a stylized nodal power-market equilibrium problem with binary on-off decisions from the literature.

We show that our approach indeed yields an exact solution to the Nash game in binary decision variables, which is incentive-compatible and therefore a deviation-proof equilibrium. We compare different implementations of actual market rules within our model, such as non-negative profit constraints and restrictions on the compensation payments, and discuss the different resulting equilibria in terms of welfare, efficiency, and allocational equity (fairness).

Session T2-B (Tuesday, June 23, 10:45AM, Meeting Room 3M-4)

### MODELING FLEXIBLE PRIMARY RESPONSE IN SECURITY-CONSTRAINED OPTIMAL POWER FLOW

**Dr. Daniel Kirschen**, Close Professor of Electrical Engineerin, University of Washington (*Seattle, Washington*)
**Mr. Yury Dvorkin**, Ph.D. Student, University of Washington (*Seattle, Washington*)
**Dr. Pierre Henneaux**, Power System Engineer, Tractebel Engineering (*Brussels, Belgium*)
**Dr. Hrvoje Pandzic**, Assistant Professor, University of Zagreb (*Zagreb, Croatia*)

Preventive Security-Constrained (PSC) Optimal Power Flow (OPF) dispatches controllable generators at minimum cost while ensuring that all operating constraints are respected for both pre- and post-contingency states without post-contingency re-dispatch. Therefore, credible generation outages must be considered in the PSC OPF. This requires that the automatic primary frequency response of the generators be taken into account. This presentation argues that instead of setting the droop coefficient uniformly across all controllable generators, it would be more economical and more secure to optimize the droop coefficient of each generator. Increasing amounts of uncontrollable renewable generation are likely to require the implementation of this optimization of primary frequency control.

The potential savings that could be achieved are assessed using a modified IEEE Reliability Test System with different levels of wind penetration. We also use these numerical simulations to assess the effectiveness of the existing N-1 primary response policy under high wind penetration levels. Our analysis suggests that this policy should be revised because it does not achieve a high level of reliability and unnecessarily increases the system security cost.

### (IM)PRECISION AND INACCURACY IN PRICE AND LOAD FORECASTS: RESILIENCY IMPLICATIONS OF COMBINING FORECAST DATA WITH SIMULATIONS OF N-K CONTINGENCIES

**Mr. Jason Veneman**, Senior Artificial Intelligence Engineer, The MITRE Corporation (*McLean, Virginia*)
**Dr. James Thompson**, Lead Operations Research Analyst, The MITRE Corporation (*McLean, Virginia*)
**Dr. Brian Tivnan**, Chief Engineer, The MITRE Corporation (*McLean, Virginia*)

Preliminary research on ISO data shows precise but inaccurate load forecasts while price forecasts appear to be both imprecise and inaccurate. Do these characteristics of power system financial data contains actionable resiliency or market manipulation information? Combining ISO load and price data with a power flow model of cascading failure we present our initial findings looking at these issues.

### PARALLEL SOLUTION OF A NONLINEAR STOCHASTIC PROGRAMMING FORMULATION FOR THE N-1 CONTINGENCY CONSTRAINED ACOPF PROBLEM

**Dr. Carl Laird**, Associate Professor, Purdue University (*West Lafayette, Indiana*)
**Ms. Anya Castillo**, Operations Research Analyst, Federal Energy Regulatory Commission (*Washington, District of Columbia*)
**Dr. Jean-Paul Watson**, Scientist, Sandia National Laboratories (*Albuquerque, New Mexico*)
**Dr. Cesar Silva-Monroy**, Scientist, Sandia National Laboratories (*Albuquerque, New Mexico*)

We present a nonlinear stochastic programming formulation for the N-1 contingency constrained ACOPF problem. This problem uses a variant of the rectangular IV formulation within a stochastic programming formulation whose extensive form includes instances of the ACOPF for nominal operation and each valid N-1 contingency. While the nonlinear ACOPF problem itself is solvable to local optimality using off-the-shelf NLP solvers, when considering realistic network sizes and all N-1 contingencies, the resulting NLP outstrips the capabilities of existing serial solvers. In addition to the problem formulation, we present timing results for a parallel decomposition algorithm that allows for efficient solution of this problem on realistic network sizes.

<u>Session T3-A (Tuesday, June 23, 1:30 PM, Meeting Room 3M-2)</u>

### USING HIGH PERFORMANCE COMPUTING TO SOLVE UNIT COMMITMENT PROBLEM

**Dr. Feng Pan**, Senior Research Engineer, Pacific Northwest National Laboratory (*Richland, Washington*)
**Dr. Stephen Elbert**, Manager, Pacific Northwest National Laboratory (*Richland, Washington*)

Unit commitment (UC) problem plays an important role in daily planning and operation of a power system. Stochastic UC models and algorithms have been developed to address uncertainties in committing generation resources. These are important problems to overcome challenges of integrating renewable generation resources and fluctuating demands. Solving deterministic UC is usually a subroutine in stochastic UC algorithms and still at the heart of making fast and cost efficient commitment decisions. Although many deterministic problems of ISO size can be solved with required time limit, the overall performances are not uniform. It has also been reported that it took considerable time to solve linear programming relaxation of UC. This talk is about solving UC with high performance computing. We will discuss recent progress made to solve deterministic day-ahead UC. We took several approaches to make UC problem distributable and smaller size. Our approaches are based on decomposition methods to separate a UC problem and solve them in parallel and on delayed constraint generation methods to reduce the problem size.

### A DISTRIBUTED APPROACH TO LARGE SCALE SECURITY CONSTRAINED UNIT COMMITMENT PROBLEM

**Dr. Kaan Egilmez**, Project Manager, Cambridge Energy Solutions (*Cambridge, Massachusetts*)

The convergence of machine virtualization and the maturing of multi-core computing has had a dramatic impact on the ease with which high performance computing techniques can be brought to bear on real world problems. We present an approach to improving the performance of our Dayzer market modeling and simulation software that makes use of multi-core parallel programming on individual compute nodes combined with a Message Passing Interface (MPI) based distribution of work load across multiple such compute nodes organized as a high performance computing cluster. We provide an overview of the techniques used and simulation results of performance improvement on large scale models such as our combined model for PJM and MISO. We argue that these techniques if applied to market operations and planning would allow many more scenarios to be concurrently examined and/or more detailed individual models to be solved within reasonable time limits allowing novel solutions to existing concerns regarding robustness of market results to various kinds of uncertainties.

### DECENTRALIZED ROBUST OPTIMIZATION ALGORITHMS FOR TIE-LINE SCHEDULING OF MULTI-AREA GRID WITH VARIABLE WIND ENERGY

**Dr. Bo Zeng**, Professor, University of South Florida (*Tampa, Florida*)
**Mr. Zhigang Li**, Graduate Assistant, Tsinghua University (*Beijing, China*)
**Dr. Mohammad Shahidehpour**, Professor, Illinois Institute of Technology (*Chicago, Illinois*)
**Dr. Wenchuan Wu**, Professor, Tsinghua University (*Beijing, China*)
**Dr. Boming Zhang**, Professor, Tsinghua University (*Beijing, China*)

Interactions among regional power systems, and particularly the large-scale integration of wind energy generate a critical need to coordinate multi-area generation and dispatch through tie-line scheduling. Given the restrictions on private data exchange and model management, it is desired to address such multi-area power scheduling problem in a decentralized fashion.

In this regard, we employ two-stage robust optimization scheme to formulate the centralized generation and dispatch problem with variable wind energy for a multi-area system, and develop fully decentralized algorithms for individual regional systems. Specifically, the centralized model is decomposed using the alternating direction multiplier method (ADMM) in a completely decentralized way, where only the tie-line information and decisions are exchanged. Then, the column-and-constraint generation (C&CG) method is incorporated to solve the regional robust subproblems. For dispatch problem, this integrated computing method converges to a global optimal solution. For non-convex generation problem with binary commitment decisions, a tractable procedure is developed to obtain high quality solutions. A few novel enhancement strategies are developed that reflect the nature of solving robust optimization problem in a decentralized fashion. Numerical study on IEEE 3-area RTS and 118-bus systems will be presented to demonstrate the computational performance, the solution quality, and scalability of our method.

Session T3-B (Tuesday, June 23, 1:30 PM, Meeting Room 3M-4)

**A CORRECTIVE APPROACH TO SECURITY CONSTRAINED UNIT COMMITMENT AND DISPATCH**

**Dr. Assef Zobian**, President, Cambridge Energy Solutions (*Cambridge, Massachusetts*)

In this presentation we propose a deviation from the standard “passive” SCUC and SCD, where the system operator can use available resources post contingency to resolve constraint limits violation. The standard SCUC and SCD approaches limit the pre-contingency power flows so that the post contingency flows do not exceed long term emergency limits before taking any corrective action by ISO. In the proposed approach, and for a set of constraints, available post contingency corrective actions are included in the optimization, and the short term emergency limits are used. This approach increases both the electric power system and market efficiency by increasing the transmission system capacity available to the market, but might require higher level of operating reserve requirements (and trade off between congestion cost and higher operating reserves cost) and increase the use of flexible resources. Some ISOs currently have ad hoc procedures that address and solves targeted constraints through the use of special protection systems (SPSs). This approach is a generalization of these ad hoc procedures.

**PROBABILISTIC SECURITY-CONSTRAINED UNIT COMMITMENT WITH GENERATION AND TRANSMISSION CONTINGENCIES**

**Dr. Miguel Ortega-Vazquez**, Assistant Professor, University of Washington (*Seattle, Washington*)
**Mr. Yury Dvorkin**, PhD Student, University of Washington (*Seattle, Washington*)
**Dr. Ricardo Fernandez Blanco Carramolino**, Research Associate, University of Washington (*Seattle, Washington*)

In order to respond to generators and transmission contingencies, system operators must allocate sufficient reserve to avoid resorting to load shedding. Such reserve has been allocated using deterministic criteria (e.g., N-1), which hedges the system against some credible contingencies by allocating sufficient spare capacity in both, generation and transmission assets. However, these criteria ignore the failure rates of individual generators and transmission lines, their impact on the system’s reliability, and the energy re-distribution under contingencies resulting in excessive or insufficient amounts of reserve in different parts of the grid.

This work proposes to assess the generation and transmission contingencies under a probabilistic framework using a unit commitment (UC) model that minimizes the expected operating cost in the pre- and post-contingency states. This approach performs a cost/benefit analysis for to optimize the amount and allocation of reserve, taking into account not only its cost, but also its likelihood of deployment in real-time. The proposed approach and the advantages of using it are analyzed via day-ahead simulations on a modified IEEE RTS.

**IDENTIFYING AND CONTROLLING RISKY CASCADING FAILURES OF TRANSMISSION SYSTEMS**

**Dr. Daniel Bienstock**, Professor, Columbia University (*New York, New York*)

This work tackles two related topics:
(1) We consider the problem of identifying risky contingencies in an AC power transmission system. We study contingencies that result in the loss of voltage, or large phase angle differences (in lines) or large loss of loads. Even though contingencies arise as discrete events, we model contingencies as continuous changes in line impedances, and solve a related optimization problem in such a way to obtain a sparse solution; e.g. an attack that focuses on a small number of network elements.
(2) We consider the online computation of robust controls used to ride-out a cascade, using the Stochastic Average Approximation method (SAA) so as to include "noise" (or ill-understood uncertainty) into the model.

This work is jointly done with T. Kim and S. Wright (Wisconsin) and G. Grebla (Columbia).

Session T4-A (Tuesday, June 23, 3:15 PM, Meeting Room 3M-2)

**SMART-INVEST: A STOCHASTIC, DYNAMIC POLICY MODEL FOR OPTIMIZING INVESTMENT IN WIND, SOLAR AND STORAGE**

**Dr. Warren Powell**, Professor, Princeton University (*Princeton, New Jersey*)
**Dr. Javad Khazaei**, Post-doctoral Associate, Princeton University (*Princeton, New Jersey*)

SMART-Invest is an aggregate version of the stochastic unit commitment problem that captures hourly, daily and seasonal variations of wind, solar and loads. It optimizes investment in wind, solar and storage using a model that captures the dynamics of planning steam generation (a day in advance), gas turbines (an hour in advance), and real-time economic dispatch. It captures the full generator stack, but only in aggregate, without modeling the grid itself. Day-ahead and hour-ahead forecasts are used for wind and solar to capture the stochastic behavior and the need to do advance planning. An optimized robust reserve policy is used to handle the uncertainty in forecasts. The model simulates this planning process through an entire year to capture seasonal variations, in addition to the full range of weekly, daily and hourly patterns of wind, solar and loads. Each week is run in parallel, allowing a week to be simulated very quickly. Then, an outer loop is used to optimize the investment in wind, solar and storage, allowing it to capture the marginal value of each type of investment in the presence of very realistic models of the variability of each generation and load process. The model is then used to provide a much more detailed analysis of the effect of fossil prices, the cost of wind, solar and storage, and the effect of carbon taxes, accurately capturing the marginal value of each resource.

**LARGE-SCALE STOCHASTIC PROGRAMMING TO COOPTIMIZE NETWORKS AND GENERATION IN THE FACE OF LONG-RUN UNCERTAINTIES: WHAT LINES SHOULD WE BUILD NOW?**

**Dr. Benjamin Hobbs**, Professor, Johns Hopkins University (*Baltimore, Maryland*)
**Mr. Jonathan Ho**, Research Staff, Johns Hopkins University (*Baltimore, Maryland*)
**Ms. Evangelia Spyrou**, PhD Student, Johns Hopkins University (*Baltimore, Maryland*)
**Dr. Pearl Donohoo**, Post Doctoral Associate, Johns Hopkins University (*Baltimore, Maryland*)
**Mr. Qingyu Xu**, MS Student, Johns Hopkins University (*Baltimore, Maryland*)
**Mr. Sang Woo Park**, Undergraduate Student, Johns Hopkins University (*Baltimore, Maryland*)
**Ms. Jasmine Ouyang**, Analyst, Ethree (*San Francisco, California*)
**Dr. James McCalley**, Professor, Iowa State University (*Ames, Iowa*)
**Mr. Randell Johnson**, Principal, Energy Exemplar (*Hartford, Connecticut*)

Cooptimization optimizes transmission investments anticipating on they affect incentives for siting and operating generation and other resources. Stochastic (multistage) programming identifies optimal near term transmission reinforcements, recognizing their performance under multiple regulatory, economic, and technology scenarios, and how they help or hinder system adaptability in the face of those scenarios. Case studies are under way or have been completed for WECC, BPA, and the Eastern Interconnection to show the benefits of cooptimization and stochastic programming for assessing transmission investments. The models are large scale, from several hundreds of thousands to tens of millions of variables. We describes what can be learned from such studies, computational performance, and challenges to the use of the methods.

**ELECTRICITY MARKET SOLUTIONS FOR GENERATOR REVENUE SUFFICIENCY WITH INCREASED VARIABLE GENERATION**

**Dr. Todd Levin**, Energy Systems Engineer, Argonne National Laboratory (*Lemont, Illinois*)
**Dr. Audun Botterud**, Energy Systems Engineer, Argonne National Laboratory (*Lemont, Illinois*)

We present a computationally efficient integer representation of expansion and commitment decisions to determine least-cost power system operation. The model is applied to a test case approximation of the ERCOT system to analyze the impact of increasing wind power capacity on the optimal generation mix and generator profitability. Operating reserve demand curves (ORDC) are included in the objective function to represent the system benefit of spinning and non-spinning reserves. This benefit increases with wind penetration and is based on loss-of-load probabilities and an assumed value of lost load. We also model two other market policies that can support resource adequacy: Fixed Reserve Scarcity Prices (FRSP) in the day-ahead market, and longer-term capacity payments. The optimal expansion plans under ORDC and FRSP implementation are comparable, while capacity payments lead to additional new capacity. Under baseline assumptions, only new natural gas combustion turbine (NGCT) units are developed. The FRSP policy leads to frequent reserves scarcity events and corresponding price spikes, while the ORDC policy results in a more continuous spectrum of energy prices and lower average prices overall. Average system energy prices decrease with increasing wind under all policies, as do revenues for baseload and wind generators. Therefore, some additional market incentives may be required to ensure long term resource adequacy in systems with high variable resource penetration.

**A SCALABLE SOLUTION FRAMEWORK FOR STOCHASTIC TRANSMISSION AND GENERATION PLANNING PROBLEMS**

**Dr. Francisco Munoz**, Dr., Sandia National Laboratories and Universidad Adolfo Ibañez (*Albuquerque, New Mexico*)
**Dr. Jean-Paul Watson**, Distinguished Member of Technical Staff, Sandia National Laboratories (*Albuquerque, New Mexico*)

Current commercial software tools for transmission and generation investment planning have limited stochastic modeling capabilities. Because of this limitation, electric power utilities generally rely on scenario planning heuristics to identify potentially robust and cost effective investment plans for a broad range of system, economic, and policy conditions. Several research studies have shown that stochastic models perform significantly better than deterministic or heuristic approaches, in terms of overall costs. However, there is a lack of practical solution approaches to solve such models. We propose a scalable decomposition algorithm to solve stochastic transmission and generation planning problems. Given stochasticity restricted to loads and wind, solar, and hydro power output, we develop a simple scenario reduction framework based on a clustering algorithm, to yield a more tractable model. The resulting stochastic optimization model is decomposed on a scenario basis and solved using a variant of the Progressive Hedging (PH) algorithm. Our numerical simulations are performed both on a commodity workstation and on a high-performance cluster. The results indicate that large-scale problems can be solved to a high degree of accuracy in at most two hours of wall clock time.

Session T4-B (Tuesday, June 23, 3:15 PM, Meeting Room 3M-4)

**THE IMPORTANCE OF DEFINING AND FORMULATING OPERATING RESERVE REQUIREMENTS AND DEPLOYMENTS**

**Mr. Erik Ela**, Senior Technical Leader, EPRI (*Palo Alto, California*)
**Eamonn Lannoye**, EPRI (*Palo Alto, California*)
**Aidan Tuohy**, EPRI (*Palo Alto, California*)
**Bob Entriken**, EPRI (*Palo Alto, California*)
**Russ Philbrick**, Polaris Systems Optimization (*Shoreline, Washington*)

This presentation will describe some new research evaluating the conceptual view of the how, why, when, and where of operating reserve requirements and operating reserve deployments. Topics will include how stochastic optimization can be used to inform optimal operating reserve requirements and placements in deterministic formulations, the importance of ramp and power constraints across the correct time interval (e.g., begin/middle/end timestamp), how reserve requirements differ with time-coupled multi-period market models, and important price formation topics with implicit and explicit reserve requirements. Analysis from simulations using sophisticated, multi-cycle, multi-timescale models will be presented to support the conceptual arguments. The presentation will also conclude with some critical research areas that should be explored in the future.

### RAMPING EFFECT ON FORECAST USE: INTEGRATED RAMPING AS A MITIGATION STRATEGY

**Dr. Clayton Barrows**, Energy Analyst, National Renewable Energy Laboratory (*Golden, Colorado*)
**Dr. Victor Diakov**, Energy Analyst, National Renewable Energy Laboratory (*Golden, Colorado*)
**Dr. Greg Brinkman**, Energy Analyst, National Renewable Energy Laboratory (*Golden, Colorado*)
**Mr. Aaron Bloom**, Section Supervisor, National Renewable Energy Laboratory (*Golden, Colorado*)
**Dr. Paul Denholm**, Energy Analyst, National Renewable Energy Laboratory (*Golden, Colorado*)

Currently, unit commitment (UC) and economic dispatch (ED) are based on power (MW) matching the load (or net-load) forecast with generation from dispatched units. As the net load varies from one scheduling interval to the next, the dispatched generation is ramped correspondingly. Ramping affects the overall energy (MWh) output and influences economic and reliability metrics. The shift is especially significant during load peak hours and when sharp changes in ramp rates are present. Switching to smaller scheduling intervals (from hourly to 5 min) does not eliminate the problem.

Within the Integrated Ramping approach, the net load forecast values are changed to compensate for the ramping shift. The proposed approach neither requires extra computing power nor makes the UC/ED problem more complex: the same "traditional" dispatch solver is applied to the re-calculated forecasts. This (Integrated Ramping) approach removes the power-energy discrepancy, which in turn reduces the amount of corrective measures in regulation. This is equivalent to adding free automatic generation control (AGC) in the system. Preliminary estimates based on our previous work show a 10% reduction in load variability due to Integrated Ramping for both hourly and 5-min scheduling.

### A STUDY ON WIND DISPATCHABILITY

**Dr. Feng Qiu**, Postdoctoral Appointee, Argonne National Laboratory (*Lemont, Illinois*)
**Dr. Jianhui Wang**, Computational Engineer, Argonne National Laboratory (*Lemont, Illinois*)

Renewable generation, such as wind and solar, has been treated as non-dispatchable resources in power system operations due to its uncontrollable availability. Because of their extremely low production costs, in most electricity markets renewable resources are dispatched to their maximal availability unless congestions are caused. Conventional generation resources are used to match the gap. As renewable generation is highly uncertain and its variation can be drastic, spinning reserves and other fast-response resources are required to be standby to follow the variation. As the renewable penetration continues to grow, the demand and costs for fast-response resources have become more and more significant. In this study, we treat the output levels of wind generation as highly dispatchable resources. We propose a framework to address the wind uncertainty and variation simultaneously by exploiting the probabilistic structures of the wind resources and power flows. We conduct computational experiments to investigate the effect of the proposed framework on the tradeoff between wind dispatchability and system reserves.

### Scheduling of Commitment, Energy and Reserves Under Uncertainty in a Two-Settlement Framework

**Dr. Ray Zimmerman**, Senior Research Associate, Cornell University (*Ithaca, New York*)
**Dr. Alberto Lamadrid**, Assistant Professor, Lehigh University (*Bethlehem, Pennsylvania*)
**Mr. Daniel Muñoz-Álvarez**, Graduate Student, Cornell University (*Ithaca, New York*)
**Dr. Carlos Murillo-Sánchez**, Professor, Universidad Nacional de Colombia (*Manizales, Colombia*)
**Dr. Robert Thomas**, Professor Emeritus, Cornell University (*Ithaca, New York*)

We examine the technical and economic tradeoffs between a stochastic scheduling model and a deterministic method that emulates current practice, identifying key differences in unit commitment, provision of energy and ancillary services, their pricing and the overall security of the system. The proposed model belongs to a class of probabilistic, security constrained unit commitment (SCUC) and Optimal Power Flow (OPF) problems, where emphasis is given to explicit modeling of the operational characteristics of the technologies available, their spatial and temporal coupling, and the regulatory constraints that assure reliability and adequacy.

The comparison is structured as a two settlement framework, where the first settlement determines the unit commitment and reserve allocations to maximize expected net benefits over the planning horizon subject to inter-temporal constraints and costs. The second settlement determines optimal dispatch, using a single-period optimization where the uncertainty of the renewables and demand has been revealed. The performance of both approaches is compared using a day-ahead probabilistic forecast the first settlement, followed by a set of corresponding sample trajectories for the second settlement. We describe the two-settlement design for each approach and present simulation results, discussing the implications for future market design.

Wednesday, June 24

Session W1-A (Wednesday, June 24, 8:30 AM, Meeting Room 3M-2)

**A STOCHASTIC DISPATCHABLE PRICING SCHEME FOR ELECTRIC ENERGY DAY-AHEAD MARKETS**

**Dr. John Birge**, Professor, University of Chicago (*Chicago, Illinois*)
**Dr. Audun Botterud**, Scientist, Argonne National Laboratory (*Argonne, Illinois*)
**Mr. Chao Li**, Student, Arizona State University (*Tempe, Arizona*)

A well-designed pricing scheme should provide a proper pricing signal and be incentive compatible. The currently utilized locational marginal price scheme releases a proper pricing signal for dispatch, but fails to capture commitment costs. Moreover, price inconsistency exists between day-ahead and real-time markets under the current deterministic pricing scheme. As more intermittent renewable resources are being introduced to power grids, the inconsistency is expected to be amplified. In this presentation, a stochastic all-units-dispatchable locational marginal price scheme is proposed to better represent the non-convexity and uncertainty in electric energy day-ahead markets. The stochastic pricing framework is adopted by including a number of real-time forecast scenarios into the pricing model. In addition, by relaxing all units to be fully dispatchable, the pricing model can be separated from the unit commitment solution. Test results show that the proposed pricing scheme reduces the need for uplift payments and the price inconsistency between day-ahead and real-time markets. Furthermore, price jumps occur less often and prices are more likely to increase with the load level. Finally, the proposed pricing scheme gives incentives for market participants to invest in low-variable-cost generation technologies.

**A NEW DUAL DECOMPOSITION METHOD AND PARALLEL SOFTWARE IMPLEMENTATION FOR LARGE-SCALE STOCHASTIC MIXED-INTEGER PROGRAMS**

**Dr. Kibaek Kim**, Postdoctoral Appointee, Argonne National Laboratory (*Lemont, Illinois*)
**Dr. Victor M. Zavala**, Computational Scientist, Argonne National Laboratory (*Lemont, Illinois*)

We develop algorithmic innovations for the dual decomposition method to address two-stage stochastic programs with mixed- integer recourse and provide a parallel software implementation that we call DSP. Our innovations include the derivation of valid inequalities that tighten Lagrangian sub- problems and that allow the recovery of feasible solutions for problems without (relative) complete recourse property. We also stabilize dual variables by solving the Lagrangian master problem with a primal-dual interior point method and provide termination criteria that guarantee finite termination of the algorithm. DSP can solve instances specified in C code, SMPS files (a standard format for stochastic programming), and StochJump (a Julia- based algebraic modeling language). DSP also implements a standard Benders decomposition method and a dual decomposition method based on subgradient dual

updates that we use to perform benchmarks. We present numerical results using standard SIPLIB instances and a large-scale unit commitment problem to demonstrate that the innovations provide significant improvements in the number of iterations and solution times.

**PRESERVING REVENUE ADEQUACY IN FTR MARKETS WITH CHANGING TOPOLOGY**

**Dr. Aleksandr Rudkevich**, President, Newton Energy Group LLC (*Boston, Massachusetts*)
**Mr. Evgeniy Goldis**, PhD Student, Boston University (*Boston, Massachusetts)*
**Dr. Michael Caramanis**, Professor, Boston University (*Boston, Massachusetts)*
**Dr. Pablo Ruiz**, Research Associate Professor, Boston University (*Boston, Massachusetts)*
**Mr. Xiaoguang Li**, Research Fellow, Boston University (*Boston, Massachusetts)*
**Dr. Ricahard Tabors**, President, Tabors Caramanis Rudkevich (*Boston, Massachusetts)*

FTR revenue inadequacy occurs when the total amount of congestion charges collected in the energy market is insufficient to meet the payout obligations to all FTR holders. One of the major causes of this revenue inadequacy is the mismatch between the transmission topologies used in the FTR allocation and auction processes and the topologies realized in the day-ahead market settlements. The topology mismatches are mostly due to differences in the planned transmission outage schedules used in FTR auctions and the realized outage schedules, forced transmission outages and the use of switching solutions. In this presentation we introduce a special class of financial rights, Topology Reconfiguration Rights (TRRs), which represent the economic value of each mismatch between the network topology used in the relevant FTR auction and the ones realized in the energy market. We prove that the combination of FTRs and TRRs is always simultaneously feasible and revenue adequate. Implementation of the proposed approach fully preserves the hedging function of FTRs while guaranteeing revenue adequacy under changes in topology.

Session W1-B (Wednesday, June 24, 8:30 AM, Meeting Room 3M-4)

**ENSURING THE OPERATIONAL SECURITY OF POWER GRIDS USING THE ON-LINE DYNAMIC SECURITY ASSESSMENT TECHNOLOGY**

**Dr. Lei Wang**, Director, Software Technologies, Powertech Labs Inc. (*Surrey, British Columbia*)

Secure operation of power systems is of ultimate importance to the reliable supply of electricity and efficient operation of power market. A new technology for security analysis, named on-line dynamic security assessment (OLDSA), has emerged in recent years as a promising alternative to the conventional approach based on the off-line studies. OLDSA incorporates advanced concepts on modeling, computations, and software development. With this technology, security analysis is performed using the real-time (or forecast) system conditions obtained through SCADA/WAMS or other databases, and valuable information is provided to grid operators for applications such as identification of potential security bottleneck in the system, optimization of operation of renewables, minimization of reserve and congestion management cost, restoration of systems after blackouts, etc. OLDSA technology has been applied for various time frames, from real time to day ahead to long term (months). Software systems with OLDSA functionality have been installed and operational in control rooms of a number of major grid operators, including PJM, MISO, California ISO, and ERCOT.

This presentation describes the technical approach of OLDSA technology, including modeling, analysis methods, software architecture, and integration with other data/software systems in control rooms. The application areas and status of this technology, as well as some of the benefits achieved, are also discussed with examples.

### Grid Architecture as a Means to Understand the Interactions of Power Systems, Markets, and Grid Control Systems

**Dr. Jeffrey Taft**, Chief Architect, Pacific Northwest National Laboratory (*Richland, Washington*)

Present grid modernization efforts are driving new technologies into the grid at an unprecedented pace to serve a variety of new goals and emerging trends not contemplated for the 20th Century grid. Where centralized wholesale markets exist, the careful integration of markets and bulk system controls is being challenged by the essentially viral introduction of distributed generation and other Distributed Energy Resources (DER). Given that many of these resources are a) Distribution-connected and b) not owned by traditional utilities, the interaction of markets for DER, the bulk system and distribution level control systems, and even industry structure, have become paramount. The questions of efficient aggregation, allocation, and dispatch of DER are becoming strongly entangled with operational issues of control, communication, and coordination, as well as industry, market, and regulatory structure.

The discipline of Grid Architecture is being recognized at the Department of Energy and in the utility industry as a strong tool for reasoning about grid modernization and emerging grid complexity. This paper will introduce some basics of Grid Architecture and show how it can facilitate thinking about the integration of large scale DER with grid operations and markets, and interaction of markets and controls in a massively penetrated DER environment.

### Predicting Predictions: The Use of Bayesian Model Averaging To Select Models

**Mr. Colin Gounden**, Chief Executive Officer, Via Science (*Cambridge, Massachusetts*)
**Dr. Jeremy Taylor**, Vice President, Lead Scientist, Via Science (*Montréal, Quebec*)

Analytical methods to make predictions and model complex systems are proliferating. It is unlikely that any single algorithm or model will provide optimal decisions in all circumstances in perpetuity. In this presentation, we argue that a systematic approach to aggregate multiple models using a weighted average dependent upon circumstances such as weather, provides decision support with lower variability and greater accuracy. In particular, we propose a Bayesian Model Averaging (BMA) approach and a software architecture that can be used to implement BMA in operational environments. This presentation argues that we are relatively close to being able to improve predictions and modeling through the use of well-understood mathematical principles and existing software architectures.

Session W2-A (Wednesday, June 24, 10:15 AM, Meeting Room 3M-2)

**TOPOLOGY CONTROL ALGORITHMS IMPACTS IN DAY-AHEAD MARKETS - SIMULATIONS IN PJM**

**Dr. Pablo Ruiz**, Senior Associate, The Brattle Group (*Cambridge, Massachusetts*)
**Dr. Michael C. Caramanis**, Professor, Boston University (*Boston, Massachusetts*)
**Mr. Evgeniy Goldis**, Chief Technology Officer, Newton Energy Group (*Boston, Massachusetts*)
**Ms. Bhavana Keshavamurthy**, Senior Engineer, PJM Interconnection (*Valley Forge, Pennsylvania*)
**Mr. Xiao Li**, Research Fellow, Boston University (*Boston, Massachusetts*)
**Dr. C. Russ Philbrick**, President, Polaris Systems Optimization (*Shoreline, Washington*)
**Dr. Aleksandr Rudkevich**, President, Newton Energy Group (*Boston, Massachusetts*)
**Dr. Richard Tabors**, President, Tabors Caramanis Rudkevich (*Boston, Massachusetts*)

Transmission topology control (line switching) supports congestion management by routing power flow away from congested or overloaded facilities. The result is an increase in transfer capabilities from low-cost resources to demand centers with significant potential for economic and reliability benefits. However, due to the computational complexity of the problem, its use has been limited, employed on an ad-hoc basis and relying on operators' previous experience or a set of fixed procedures. Our previous work developed near-optimal and tractable topology control algorithms (TCA) for use operations decision processes in which unit commitment is pre-specified. For example, we have evaluated the use of TCA in real-time market optimization, transmission and generation outage coordination and scheduling, and development of operating guides in seasonal contingency planning.

This presentation will report on simulation results of TCA impacts on historical PJM day-ahead market models. The addition of transmission topology decisions to the security-constrained unit commitment model in the day-ahead market optimization provides more efficient outcomes while meeting reliability standards.

### FLEXIBLE TRANSMISSION DECISION SUPPORT SYSTEMS

**Dr. Kory Hedman**, Professor, Arizona State University (*Tempe, Arizona*)
**Dr. Mostafa Sahraei-Ardakani**, Post Doctoral Scholar, Arizona State University (*Tempe, Arizona*)
**Ms. Mojdeh Abdi-Khorsand**, PhD Student, Arizona State University (*Tempe, Arizona*)
**Mr. Xingpeng Li**, PhD Student, Arizona State University (*Tempe, Arizona*)
**Mr. Pranavamoorthy Balasubramanian**, PhD Student, Arizona State University (*Tempe, Arizona*)
**Mr. Akshay Korad**, PhD Student, Arizona State University (*Tempe, Arizona*)

Existing energy management systems (EMS) and market management systems (MMS) inefficiently utilize transmission assets. While there is a critical need to modernize the way electricity is delivered via real-time optimization of power flow control devices, EMS and MMS systems neglect existing power flow control technologies. In particular, existing EMS and MMS systems neglect transmission switching.

Flexible Transmission Decision Support (FTDS) provides low-cost software solutions for power flow control. With advanced optimization software, FTDS delivers real-time decision support that enables power to be redirected around transmission bottlenecks to enhance reliability and lower operational costs. Prior demonstration of FTDS on one week of EMS data from PJM has shown transmission control actions can reduce the set of critical contingencies by at least half, thereby substantially reducing operational costs.

This presentation will focus on post-contingency corrective switching actions. PJM has already identified over 100 potential switching solutions in their M-03 transmission manual. FTDS has been applied to one week of actual operational EMS data provided by PJM. We will show how FTDS is able to identify, in real-time, the solutions already proposed by PJM and we will demonstrate that FTDS also proposes switching solutions that are better than the ones identified by PJM. FTDS is also able to identify additional switching solutions not previously determined by PJM.

### CO-OPTIMIZATION OF BATTERY STORAGE OVER MULTIPLE REVENUE STREAMS AND TIME SCALES

**Dr. Warren Powell**, Professor, Princeton University (*Princeton, New Jersey*)
**Mr. Harvey Cheng**, Graduate Student, Princeton University (*Princeton, New Jersey*)

Maximizing the value of battery storage requires taking advantage of multiple revenue streams. This requires optimizing across different time scales, spanning the response to frequency regulation signals every two seconds (typically the largest revenue stream) to battery arbitrage, energy shifting and peak shifting which requires holding energy for minutes to hours (some strategies require planning over days to weeks). Modeling a day in 2-second increments produces a dynamic program with over 43,000 time periods. Further, the information required in the state variable changes over different time scales. For example, we need to track a compliance signal for PJM which is reset every hour, and LMPs change once every 5 minutes (on the PJM grid). Following a frequency regulation signal is relatively simple, but we need to make tradeoffs between the cost of deviating from the frequency regulation signal now if, for example, we wish to store energy now to be used in the future (or discharge energy now, possibly creating a shortage later). This means it is necessary to perform cost optimization over time, while still reacting quickly to the frequency regulation signal. We propose a nested decomposition strategy that produces a near-optimal control strategy that optimizes across all of these time scales, using dynamic programs designed specifically for each time scale.

### ENERGY STORAGE: A STUDY IDENTIFYING BUSINESS CASES FOR FRANCE BY 2030

**Dr. Guillaume Tarel**, Vice President, Artelys (*Montréal, Canada*)

Flexibility is required in order to increase the efficiency of today's power markets, in particular within a context of growth of intermittent generation. I will present examples of solutions that provide flexibility: demand-response in a refinery, storage in insular regions, Euro-Mediterranean interconnections and the use of flexible generation assets.

Then, I will more specifically focus on storage. Indeed, Artelys has recently led a cost-opportunity study of storage for the French government. It has been presented to the French Minister of Industry in November 2013. Assessing storage benefits for France by 2030 was done using the software Artelys Crystal. This permits finding an optimal arbitrage between the different services provided by storage (peak demand shaving, support during network congestions etc.) some of whom are competing, while respecting technical and operational constraints. I will finally discuss what the most promising technologies according to the study are. In particular water storage, heat storage and the use of electric vehicles batteries. My conclusion will compare the case of France to other energy systems and discuss what aspects of the study are or are not very context-specific.

Session W2-B (Wednesday, June 24, 10:15 AM, Meeting Room 3M-4)

### A TOOLBOX FOR EXPLORING AC OPF FORMULATIONS, DATASETS AND SOLUTION METHODS

**Ms. Lisa Tang**, Student, University of Wisconsin - ~~–~~Madison (*Madison, Wisconsin*)
**Dr. Christopher DeMarco**, Professor, University of Wisconsin - Madison (*Madison, Wisconsin*)
**Dr. Michael Ferris**, Professor, University of Wisconsin - Madison (*Madison, Wisconsin*)
**Dr. Bernard Lesieutre**, University of Wisconsin -~~–~~ Madison (*Madison, Wisconsin*)
**Mr. Byungkwon Park**, Student, University of Wisconsin - Madison (*Madison, Wisconsin*)

While optimal power flow problems are well researched, there is a lack of cohesiveness in comparative literature due to different models, file formats, software and solvers. The GAMS model toolbox bridges that gap by providing several well-known formulations of the OPF problem, allowing the modeler to directly compare various models and explore faster, more robust solution methods for unit commitment and economic dispatch.

Data management tools also provide utilities for dataset enhancement and conversion between GAMS, Matpower and PSSE formats. In addition, we also discuss using D-curves, tap transformers, and demand bidding in these types of problems, as well as the challenges that arise in the creation and solution process of realistic and large-scale datasets.

### THE FLEX DA/RT CO-OPTIMIZATION MODEL METHOD - A BETTER UNIT COMMITMENT FOR AN UNCERTAIN GRID

**Mr. Charles Noble**, Manager, Trading Analytics, ACES (*Carmel, Indiana*)

Given the difficulty in formulating and solving full-scale stochastic unit-commitment problems, what interim steps might be taken to more intelligently incorporate information about uncertainty into unit-commitment and dispatch with the resources available to the RTO today?

We propose the adoption of methodology used by the FLEX DA/RT Co-optimization Model as a solution. This method monetizes the value of flexibility as derived from the cost and opportunity associated with uncertainty in the real-time position. These benefits are then intelligently incorporated into a model that co-optimizes these benefits with the hedging needs of the DA position to produce a deterministically derived recommended resource plan.

The premises upon which the method is based are easy to understand and explain:

- The more flexibility a resource offers the ISO/RTO, the more consideration the RTO/ISO should give to the resource. This premise should hold even if the resource does not offer ancillary services.
- Commitment of more flexible resources will be given in locations and during hours and days where and when the RT LMP price volatility is the highest. Consideration is given to specific nodal locations and hours, not just to a specific zone.
- Only additional resource flexibility that is expected to be cost effective will be recommended.

### STRONG SOCP RELAXATIONS FOR OPTIMAL POWER FLOW PROBLEMS

**Dr. Andy Sun**, Assistant Professor, Georgia Institute of Technology (*Atlanta, Georgia*)
**Mr. Burak Kocuk**, Research Assistant, Georgia Institute of Technology (*Atlanta, Georgia*)
**Dr. Santanu S. Dey**, Associate Professor, Georgia Institute of Technology (*Atlanta, Georgia*)

We propose three strong second order cone programming (SOCP) relaxations for the AC optimal power flow (OPF) problem. One of these relaxations is based on a new bilinear extended formulation of OPF. The three relaxations are incomparable to each other and two of them are incomparable to the standard SDP relaxation of OPF. Extensive computational experiments show that these relaxations have numerous advantages over existing convex relaxations in the literature: (i) their solution quality is extremely close to that of the SDP relaxations (within 99.96% of the SDP relaxation on average for all IEEE test cases) and consistently outperforms previously proposed convex quadratic relaxations of OPF; (ii) the solutions from the strong SOCP relaxations can be directly used as a warm start in a local solver such as IPOPT to obtain a high quality feasible OPF solution; and (iii) the strong SOCP relaxations can be solved orders of magnitude faster than SDP relaxations. For example, the proposed SOCP relaxation with IPOPT produces a feasible solution for the largest instance in the IEEE test cases (the 3375-bus system) and also certifies that this solution is within 0.13% of global optimality, all within 133.62 seconds on a modest personal computer. Overall, the proposed SOCP relaxations provide a practical approach to obtain feasible OPF solutions with extremely high quality within a time framework that is compatible with the real-time operation in the current industry practice.

## ADDRESSING UNCERTAINTY HOW TO MODEL AND SOLVE ENERGY OPTIMIZATION PROBLEMS

**Dr. Alkis Vazacopoulos**, Director, Optimization Direct, Inc. (*Harrington Park, New Jersey*)

During the past twenty years, IBM’s CPLEX Optimization Studio has been used extensively to solve hard Energy Optimization Problems. CPLEX Optimization Studios modeling capabilities, fast solvers and easy deployment features empower users to deploy energy applications quickly and reliably. Now, with a newly update superset offering know as Decision Optimization Center, the capabilities for this class of problems is greatly enhanced. Using the Unit Commitment Problem as a paradigm, we will demonstrate the advantages of using Decision Optimization Center, and CPLEX for modeling complex problems and application developments in the Energy Field.

Most importantly we will introduce new research developed for solving problems that address Uncertainty. We will showcase a new research approach that allows the user to test and deploy Stochastic, Robust or Deterministic models all on the same platform. This new approach allows you to truly understand your options as you explore the best plan for your business and develop a robust and repeatable process.